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

X **Annual Report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: December 31, 2008
Commission File Number: 001-32754

BAYTEX ENERGY TRUST
(Exact name of Registrant as specified in its charter)

Alberta	**1311**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

Suite 2200, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 2V7
(403) 269-4282
(Address and telephone number of registrant's principle executive offices)

CT Corporation System
111 Eighth Avenue
New York, NY 10011
(212) 894-8940
(Name, address (including zip code) and telephone number
(including area code) of agent for service in the United States)

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

Title of each class:	Name of each exchange on which registered:
TRUST UNITS	**New York Stock Exchange**
Toronto Stock Exchange	

Securities registered pursuant to Section 12(g) of the Act:
NONE

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
NONE

For annual reports, indicate by check mark the information filed with this form:
X Annual Information Form **X** Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
97,685,333 Trust Units were outstanding as of December 31, 2008.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.
Yes No **X**

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 **X** No

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 40-F are forward-looking statements within the meaning of Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"), and Section 27A of the Securities Act of 1933, as amended. Please see "Special Note Regarding Forward-Looking Statements" on page 3 of the Annual Information Form, which is Exhibit 99.1 of this Annual Report on Form 40-F.

Principal Documents

The Registrant is the sole common shareholder of Baytex Energy Ltd. (the "Company"). The Company has been allocated the responsibility for significant strategic management and operational decisions of the Registrant pursuant to the trust indenture creating the Registrant and an administration agreement between the Registrant and the Company. The Registrant has no directors or officers.

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

A. Annual Information Form

For the Annual Information Form for the year ended December 31, 2008, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2008, including the report of our Independent Registered Chartered Accountants with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F. For a reconciliation of differences between Canadian and United States generally accepted accounting principles, see note 19 of the Notes to the Consolidated Financial Statements.

C. Management's Discussion and Analysis

For Management's Discussion and Analysis for the year ended December 31, 2008, see Exhibit 99.3 of this Annual Report on Form 40-F.

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

Controls and Procedures

A. Disclosure Controls and Procedures

As of December 31, 2008, an internal evaluation was conducted of the effectiveness of the Registrant's "disclosure controls and procedures" as defined in the United States by Rule 13a-15(e) and 15d-15(e) under Exchange Act and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings . Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Registrant's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Registrant files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein and accumulated and communicated to the Registrant's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

B. Changes in Internal Control Over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

C. Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included in the Management's Report that accompanies the Registrant's audited Consolidated Financial Statements for the year ended December 31, 2008, included as Exhibit 99.2 of this Annual Report of Form 40-F.

D. Attestation of Report of Independent Registered Chartered Accountants

The Attestation Report of the Registrant's Auditor is included in the Report of Independent Registered Chartered Accountants that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2008, included as Exhibit 99.2 of this Annual Report of Form 40-F.

Code of Ethics

The Registrant's code of ethics ("Code of Ethics"), which is applicable to its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions, is posted on the Registrant's website at www.baytex.ab.ca.

Since its adoption, the Registrant has not amended any provision of its Code of Ethics 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 granted any waiver, including an implicit waiver, from a provision of its Code of Ethics.

Auditor Fees and Services

The following table provides information about the fees billed to the Registrant for professional services rendered by Deloitte & Touche LLP, the Registrant's principal accountant, during fiscal 2008 and 2007:

	Aggregate fees billed	
	2008	**2007**
	($000s)	
Audit fees	**1,124**	**851**
Tax fees	**56**	**5**
All other fees	**84**	**133**
	1,264	**989**

Audit Fees. Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly results, services in this category for fiscal 2008 and 2007 also include the reviews of comment letters from Canadian and U.S. regulatory agencies, amounts for audit work performed in relation to the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 relating to internal control over financial reporting and review of prospectuses related to an acquisition and equity and debt issuances.

Audit-Related Fees. Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Trust's financial statements and are not reported as Audit Fees. During fiscal 2008 and 2007, there were no payments in this category.

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

All Other Fees. During fiscal 2008 and 2007, the services provided in this category consist only of advisory services associated with property taxes.

The Company's Audit Committee has pre-approved and must pre–approve all non–audit services to be provided to the Registrant or its subsidiaries by the external auditors. The Audit Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

The Company's Board of Directors has determined that Mr. Naveen Dargan 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. Mr. Dargan is a corporate director and meets the New York Stock Exchange definition of independence. For a description of Mr. Dargan's relevant experience in financial matters, see the five-year history in the section "Additional Information Respecting Baytex Energy Ltd. - Management of the Trust" in the Registrant's Annual Information Form for the year ended December 31, 2008, which is included as Exhibit 99.1 to this Annual Report on Form 40-F. The Company has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Company's Audit Committee members consist of Mr. Dargan, Mr. R.E.T. (Rusty) Goepel, and Mr. G. Melchin.

Off-Balance Sheet Arrangements

Information regarding off-balance sheet arrangements of the Registrant is included in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2008, which is filed as Exhibit 99.3 to this Annual Report on Form 40-F.

Contractual Obligations

Information regarding contractual obligations of the Registrant is included in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2008, which is filed as Exhibit 99.3 to this Annual Report on Form 40-F.

UNDERTAKING

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

CONSENT TO SERVICE OF PROCESS

A Form F-X signed by the Registrant and its agent for service of process was filed with the Commission together with the Registrant's Annual Report on Form 40-F for the fiscal year ended December 31, 2007.

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

SIGNATURES

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

Registrant: BAYTEX ENERGY TRUST

By: Baytex Energy Ltd.

(signed) "*W. Derek Aylesworth*"
Name: W. Derek Aylesworth, CA
Title: Chief Financial Officer

Date: March 26, 2009

Form 40-F Table of Contents

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2008
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2008, including reconciliation to United States generally accepted accounting principles, together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2008.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of Deloitte & Touche LLP, independent registered chartered accountants.
99.9	Consent of Sproule Associates Limited, independent engineers.

Exhibit 99.1

BAYTEX ENERGY TRUST

ANNUAL INFORMATION FORM

2008

MARCH 26, 2009

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APPENDIX B REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX C AUDIT COMMITTEE MANDATE

SELECTED TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Baytex, the **Corporation** or the **Company** means Baytex Energy Ltd.

Baytex ExchangeCo means Baytex ExchangeCo Ltd.

Baytex USA means Baytex Energy USA Ltd.

Board of Directors means the board of directors of Baytex.

Crew means Crew Energy Inc.

OPEC means the Organization of the Petroleum Exporting Countries.

SEC means the United States Securities and Exchange Commission.

Trust, **we**, **us** or **our** means Baytex Energy Trust and all its controlled entities on a consolidated basis.

Trustee means Valiant Trust Company our trustee.

Unitholders means holders of our Trust Units.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

NI 51-101 means National Instrument 51-101 "Standards of Disclosure for Oil and Natural Gas Activities" of the Canadian Securities Administrators.

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the report dated March 4, 2009 entitled " *Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2008*)".

Securities and Other Terms

Convertible Debentures means our 6.50% convertible unsecured subordinated debentures issued on June 6, 2005.

DRIP means our distribution reinvestment plan.

Exchangeable Shares means the exchangeable shares of Baytex which are exchangeable for Trust Units.

Exchange Ratio means the ratio at which Exchangeable Shares may be converted to Trust Units.

GAAP means generally accepted accounting principles in Canada.

Notes means the 12% unsecured subordinated promissory notes issued by Baytex and held by us pursuant to the plan of arrangement completed on September 2, 2003 and other promissory notes issued by Baytex or any of our subsidiaries or affiliates to us from time to time.

Note Indenture means the note indenture relating to the issuance of Notes issued on September 2, 2003.

NPI means the net profit interest in the petroleum substances owned by Baytex held by us.

NPI Agreement means the amended and restated net profit interest agreement between us and Baytex made as of September 2, 2003 providing for the creation of the NPI.

Special Voting Units means the special voting units issued by us entitling holders of Exchangeable Shares to voting rights at meetings of Unitholders.

Tax Act means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time.

Trust Indenture means the third amended and restated trust indenture between us and Baytex made as of May 20, 2008.

Trust Unit or **Unit** means a unit issued by us, each unit representing an equal undivided beneficial interest in our assets.

Trust Unit Rights Incentive Plan means our trust unit rights incentive plan.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
NGL	natural gas liquids	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	MMcf/d	million cubic feet per day
		m^3	cubic metres
		MMbtu	million British Thermal Units
		GJ	gigajoule

Other	
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 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.**
Mboe	thousand barrels of oil equivalent.
MMboe	million barrels of oil equivalent.
boe/d	barrels of oil equivalent per day.
WTI	West Texas Intermediate.
API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
$ Million	means millions of dollars.
$000s	means thousands of dollars.

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CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbl	Cubic metres	0.159
Cubic metres	Bbl	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950

CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with GAAP. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

SPECIAL NOTES TO READER

Forward-Looking Statements

In the interest of providing our Unitholders and potential investors with information about us, including management's assessment of our future plans and operations, certain statements in this Annual Information Form are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, " **forward-looking statements**"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this Annual Information Form speak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this Annual Information Form contains forward-looking statements relating to: the taxation of income trusts; potential changes to our business form; oil and gas prices; the demand for and supply of crude oil and natural gas; our distribution practice; the portion of our cash flow from operations to be allocated to cash distributions and our capital program; our ability to maintain production levels by investing approximately half of our internally generated cash flow from operations; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; the size of our petroleum and natural gas reserves; development plans for our properties; our heavy oil resource play at Seal, including our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, operating costs and the resource potential of our undeveloped land; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates and average recoveries per well; rates of production for 2009; the existence, operation, and strategy of our commodity price risk management program; funding sources for cash distributions and our capital program; and the impact of existing and proposed governmental and environmental regulation. In addition, information and statements relating to reserves and resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves and resources can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; uncertainties associated with estimating oil and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; and other factors, many of which are beyond the control of Baytex.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk 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 our 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. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this Annual Information Form.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

Description of Cash Flow from Operations

This Annual Information Form contains references to cash flow from operations derived from cash provided by operating activities before changes in non-cash operating working capital, asset retirement expenditures and decrease in deferred charges and other assets. Cash flow from operations as presented does not have any standardized meaning prescribed by GAAP, and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP.

For more information, see our " *Management's Discussion and Analysis of Financial Condition and Results of Operations* " which includes a definition of "cash flow from operations" and reconciliation to cash provided by operating activities and is accessible on the SEDAR website at *www.sedar.com*.

New York Stock Exchange

As a Canadian issuer listed on the New York Stock Exchange (the " **NYSE**"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE rules: 1) have an audit committee that satisfies the requirements of the *United States Securities Exchange Act of 1934* ; 2) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; and 3) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. We have reviewed the NYSE listing standards and confirm that our corporate governance practices do not differ significantly from such standards.

Access to Documents

Any document referred to in this Annual Information and described as being accessible on the SEDAR website at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 2200, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

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BAYTEX ENERGY TRUST

General

We are an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture. Our head and principal office is located at Suite 2200, 205 - 5 th Avenue S.W., Calgary, Alberta, T2P 2V7.

We were formed on July 24, 2003 and commenced operations on September 2, 2003 as a result of the completion of a plan of arrangement under the *Business Corporations Act* (Alberta) on September 2, 2003 involving us, Baytex, Cre Baytex Acquisition Corp., Baytex ExchangeCo, Baytex Resources Ltd. and Baytex Exploration Ltd. Pursuant to the plan of arrangement, former holders of common shares of Baytex received common shares of Crew and Trust Units, or Exchangeable Shares or a combination thereof, in accordance with the elections made by such shareholders, and Baytex became a subsidiary of us.

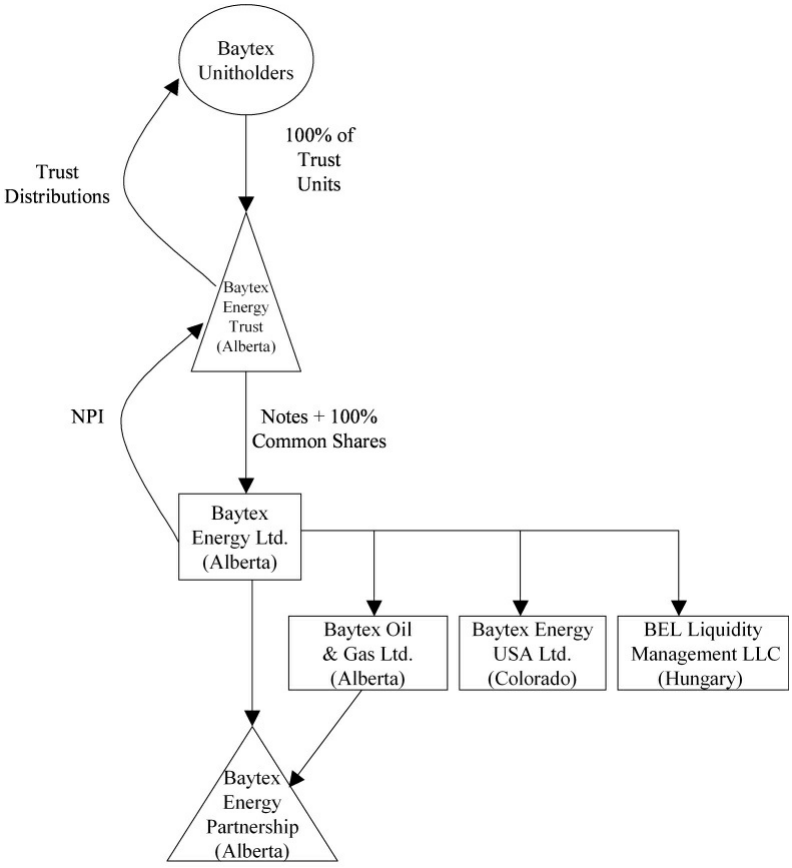
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance, formation or organization of our subsidiaries either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Baytex Energy Ltd.	100%	Alberta
Baytex Energy Partnership	100%	Alberta
Baytex Energy Oil & Gas Ltd.	100%	Alberta
Baytex Energy USA Ltd.	100%	Colorado
BEL Liquidity Management LLC	100%	Hungary

Our Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries as well as the flow of cash from the oil and gas properties held by such subsidiaries to us and from us to Unitholders.



Notes:

(1) Unitholders own 100 percent of our Trust Units.

(2) Cash distributions are made on a monthly basis to Unitholders based upon our cash flow. Our primary sources of cash flow are NPI payments from Baytex and interest on the principal amount of the Notes and other intercorporate notes. In addition to such amounts, prepayments in respect of principal on the Notes and other intercorporate notes may be made from time to time to us before the maturity of such notes.

Federal Tax Changes for Income Trusts and Corporations

In 2007, the Federal Government introduced and passed into law amendments to the Tax Act that will result in the taxation of distributions by certain specified investment flow-through trust entities (a " **SIFT**"), such as us, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "**SIFT Rules**"). The SIFT Rules provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax rate. The provincial SIFT tax rate is based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of (i) that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada and (ii) that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada. Taxable distributions that are not allocated to any province will be subject to a 10% tax rate. We would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011 and 25% in 2012.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. On December 4, 2008, the Minister of Finance announced changes to the safe harbour limits to allow a SIFT to accelerate the utilization of the SIFT annual safe harbour limit for each of 2009 and 2010 so that the safe harbour limits for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT, but it allows a SIFT to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years. These limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount carrying forward to the next year. We did not issue equity in excess of the safe harbour limits during 2006/2007 or 2008. As at December 31, 2008, we had unused safe harbour limit of $596.6 million that was carried forward, resulting in a safe harbour limit of $1,326.6 million for 2009/2010.

On July 14, 2008, Finance announced proposed amendments to the Tax Act including technical amendments to clarify certain aspects of the SIFT Rules and to provide rules to facilitate the conversion of existing SIFT trusts into corporations on a tax-deferred basis (the "**Conversion Rules**"). The Conversion Rules address many of the principal substantive and administrative issues that arise when structuring a corporate conversion of an income trust under the Tax Act. The Conversion Rules contemplate two alternatives for the conversion of a publicly-traded income trust into a taxable Canadian corporation and the winding-up of the trust's underlying structure. The first alternative involves the winding-up of the trust into a taxable Canadian corporation whereas the second approach involves the distribution by the publicly-traded income trust of shares of an underlying taxable Canadian corporation to its unitholders.

Subsequent to the year end, the Federal Government introduced draft tax legislation which included the above mentioned measures as part of Canada's Economic Action Plan. This legislation received Royal Assent on March 12, 2009, and was therefore passed into law. We continue to review the impact of the future taxation of distributions on our business strategy but at this time have made no decision as to the ultimate legal form under which we will operate post 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

For more information, see "*Risk Factors – Risks Related to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations* " and "*Risk Factors – Risks Associated with Government Regulation – C status as a mutual fund trust may be changed or affected by changes in legislation*".

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On September 2, 2003, we completed a plan of arrangement under the *Business Corporations Act* (Alberta) involving Baytex, Crew, Baytex Acquisition Corp., Baytex ExchangeCo, Baytex Resources Ltd., Baytex Exploration Ltd. and us pursuant to which former holders of common shares of Baytex received common shares of Crew and Trust Units or Exchangeable Shares, or a combination thereof, in accordance with the elections made by such shareholders, and Baytex became a subsidiary of us. Coincident with the plan of arrangement becoming effective, certain of Baytex's exploration assets were acquired by Crew, and the common shares of Crew were distributed to the former holders of Baytex common shares on the basis of one-third of a common share of Crew for each such share held.

On December 12, 2003, we completed a public offering of 6,500,000 Trust Units at a price of $10.00 per Trust Unit for gross proceeds of $65,000,000. The net proceeds of the offering were used to fund our ongoing capital expenditure and acquisition program.

On September 22, 2004, we completed the acquisition of a Calgary based private oil and gas company, for cash consideration of $109 million before adjustments. The acquisition was financed with Baytex's credit facilities and added approximately 3,000 boe/d of 65 percent gas weighted production. The assets acquired were located in two geographically focused areas of southern Alberta, Sedalia/Garden Plains and Turin/Parkland, and also included 110,000 net acres of undeveloped land. Production from this acquisition represented approximately 9.3 percent of our then existing production. Ninety-five percent of the production was from operated, high working interest properties with ownership and control of most key facilities and infrastructure within the operating areas. This acquisition added a significant inventory of drilling opportunities including low risk development and medium risk exploration to our light oil and natural gas portfolio. Opportunities also existed for re-entries, recompletions, tie-ins and workovers. Subsequent to the acquisition, the private company was amalgamated into Baytex.

On October 18, 2004, we implemented our DRIP which provides eligible Unitholders the advantage of accumulating additional Trust Units by reinvesting their cash distributions paid by us. The cash distributions are reinvested at our discretion, either by acquiring Trust Units issued from treasury at 95 percent of the "Average Market Price" (which is defined in the DRIP as the average trading price of the Trust Units on the Toronto Stock Exchange for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days) or by acquiring Trust Units at prevailing market rates. No commissions, service charges or brokerage fees are payable by participants in connection with Trust Units acquired under the DRIP. The DRIP is presently available to Canadian Unitholders only. Residents of the United States may not participate in the DRIP at this time.

On December 20, 2004, we completed a public offering of 3,600,000 Trust Units at a price of $12.80 per Trust Unit for gross proceeds of $46,080,000. The net proceeds of the offering were used to repay outstanding bank indebtedness.

On December 22, 2004, we completed the acquisition of certain strategic oil and natural gas interests in the West Stoddart area of northeast British Columbia for $90 million before adjustments. The assets acquired consisted of approximately 3,300 boe/d of primarily high netback liquids-rich natural gas production comprised of 10.0 MMcf/d of natural gas, 1,300 bbl/d of NGL and 330 bbl/d of light oil. Production from this acquisition represented approximately 9.6 percent of our then existing production. Production was mainly from three year-round access properties near Fort St. John, British Columbia (West Stoddart, North Cache and Cache Creek). The primary producing zones were the Doig, Halfway, Charlie Lake, Baldonnel and Cretaceous zones. The assets represented a new core area for us and were 100 percent operated with an average working interest of 91 percent. The acquisition also included an identified project inventory, including drilling, recompletions, fracture stimulation and well optimizations, and approximately 17,000 net acres of undeveloped land contiguous to the principal producing properties.

On June 6, 2005, we issued $100 million principal amount of Convertible Debentures for net proceeds of $95.8 million. The Convertible Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid Trust Units at a conversion price of $14.75 per Trust Unit. The Convertible Debentures mature on December 31, 2010 at which time they are due and payable. The net proceeds from the issue of the Convertible Debentures were used to reduce outstanding bank indebtedness.

On September 30, 2005, we completed the acquisition of certain heavy oil producing properties in the Celtic area in Saskatchewan for $69 million. The assets acquired consisted of 3,350 bbl/d of heavy oil (13º - 15º API) and 0.9 MMcf/d of natural gas. Production from this acquisition represented approximately 10 percent of our then existing production. The assets acquired also included approximately 7,500 net acres of undeveloped land. The Celtic properties are situated approximately 30 miles east of Lloydminster and are adjacent to our Tangleflags property. The expanded Celtic/Tangleflags operating region resulted in improved economies of scale and allowed for better control over costs. The acquisition included in excess of 100 opportunities for development drilling and recompletions for additional primary (cold) heavy oil production and natural gas production which added immediate low-cost development inventory. The acquisition also included 1,750 bbl/d of steam assisted gravity drainage ("**SAGD**") production. As part of this transaction, Baytex entered into a price-sharing arrangement and a net profits agreement for future SAGD development with the vendor with respect to the assets acquired.

On December 30, 2005, we sold the recently acquired SAGD assets in the Celtic area of Saskatchewan for $45.3 million. Production at that time from the SAGD assets was approximately 2,000 bbl/d of heavy oil.

During 2006, we did not complete any significant financings, acquisitions or dispositions.

On June 15, 2007, we completed a public offering of 7,000,000 subscription receipts (the " **Sub Receipts**") for gross proceeds of $149,450,000. Upon the June 26, 2007 closing of the property acquisition described below, the holders of the Sub Receipts received one Trust Unit in exchange for each Sub Receipt held. The net proceeds of this financing were used to partially fund the acquisition of properties at Pembina and Lindbergh described below.

On June 26, 2007, we completed the indirect acquisition of certain oil and gas producing properties in the Pembina and Lindbergh areas of Alberta for $238 million. These assets were producing approximately 4,500 boe/d of total production at the time of the acquisition. This production was comprised of 2,200 bbl/d of light oil and NGL and 8.0 MMcf/d of natural gas from the Pembina area, and 1,000 bbl/d of heavy oil from the Lindbergh area. The acquisition in the Pembina area allowed us to establish a new core area in the Nisku trend, offering greater exposure to high netback light oil and NGL targets. The assets included one of the strongest infrastructure positions in the area, which contributed to our high degree of operational control of the area, and 26,000 net acres of undeveloped land in the Pembina area. Lindbergh is a project that offers a large heavy oil resource in place that is amenable to primary (cold) production. Its shallow-depth and multiple zone character provide a low-cost source of recompletion and drilling inventory to maintain production rates. In addition to the primarily non-operated producing assets, we also acquired 11,000 net acres of 100% interest undeveloped land that may include opportunities for shallow natural gas development.

On June 4, 2008, we acquired all of the issued and outstanding shares of Burmis Energy Inc. (" **Burmis**") on the basis of 0.1525 of a Trust Unit for each Burmis common share. Approximately 6.38 million Trust Units were issued pursuan to this transaction, which was valued at approximately $180.5 million. Pursuant to this transaction, we acquired multi-zone, liquids-rich natural gas and light oil properties located in west central Alberta and approximately 110,300 net acres of undeveloped land. Production from the Burmis properties averaged 3,791 boe/d during the first quarter of 2008.

During the third quarter of 2008, we acquired a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in northwest North Dakota from a private company. Upon making all deferred payments associated with the transaction, we will have acquired a 37.5% interest in 263,000 (98,600 net) acres, 94% of which are undeveloped. In addition, we acquired approximately 300 boe/d (95% oil) of production. The seller retained the remaining 62.5% interest in the project lands and production.

Significant Acquisitions

During the year ended December 31, 2008, we did not complete any acquisitions for which disclosure was required under Part 8 of National Instrument 51-102.

Trends

Natural gas and crude oil prices are volatile and subject to a number of external factors. Natural gas is a commodity primarily influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility. Crude oil is influenced by the world economy, OPEC's ability to adjust supply to world demand and weather. For the first half of 2008, crude oil prices were kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently has been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels. The Canadian/U.S. currency exchange rate also influences commodity prices received by Canadian producers as oil and natural gas production is ultimately priced in U.S. dollars. The Canadian dollar generally follows the trend in commodity prices. During 2007, the strengthening of the Canadian dollar somewhat mitigated the economic benefit of higher prices on Canadian oil and gas producers. However, in late 2008 the weakening of the Canadian dollar partially mitigated the effect of lower prices on Canadian oil and gas producers.

The impact on the oil and gas industry from commodity price volatility is significant. During period of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

The efforts of energy trusts to replace annual production declines have been a factor resulting in high levels of competition for the acquisition of oil and natural gas properties and related assets. This increased competition has raised valuation parameters for corporate and asset acquisitions. Those trusts with opportunities to replace production economically through internal development drilling may be in a favourable position relative to those more exposed to replacing production through acquisitions.

Another trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that various environmental initiatives will have on the sector and, in more recent times, by the SIFT Rules. See "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations* " and "*Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations* ".

RISK FACTORS

You should carefully consider the following matters, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations.

Information contained in this Annual Information Form contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled " *Special Notes to Reader –Forward-Looking Statements*".

Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "– *Certain Risks for United States and other non-resident Unitholders"*.

Risks Relating to our Revenues

Our business depends on volatile oil and gas prices

The operational results and financial condition of our operating entities and therefore the amounts paid to us will be dependent on the prices received for oil and natural gas production. The prices for oil and natural gas may be volatile and subject to fluctuation. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, and political stability in the Middle East and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and cash flow from operations. Any movement in oil and natural gas prices could have an effect on our financial condition and therefore on the amounts to be distributed to our Unitholders.

We may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we will forego the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to losses. As at December 31, 2008, our balance sheet reflected $83.4 million of unrealized gains resulting from hedges to protect our commodity risk exposure. To the extent that we engage in risk management activities related to commodity prices, we will be subject to credit risks associated with counterparties with which we contract.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. See "*– Risks Relating to our Operations – Project delays may delay expected revenues from operations*" and "*– Risks Associated with Acquisitions and Dispositions – We may not realize anticipated benefits of acquisitions and dispositions or manage our growth* ".

Variations in interest rates and foreign exchange rates could affect our ability to service our debt

World oil prices are quoted in Unites States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our net production revenue.

In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar negatively impact our production revenues which may affect future distributions. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by our independent evaluator.

From time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate. As at December 31, 2008, our balance sheet reflected $2.3 million of unrealized gains resulting from hedges to protect our currency risk exposure. To the extent that we engage in risk management activities related to foreign exchange rates, we will be subject to credit risk associated with counterparties with which we contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, as well as impact the market price of the Trust Units.

The global financial crisis could adversely affect us

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively affected company and trust valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

We may be subject to refinancing risk and increased debt service charges

We currently have a $485 million syndicated credit facility. At December 31, 2008, we had approximately $183 million of unused credit available under our credit facility. In normal circumstances, borrowers such as us rely on the fact that the banks will honour their contractual commitments to fund draws as required. In today's economic environmental there is a risk that one or more of the banks included in our syndicate may not honour draws requested by us and thereby effect our ability to maintain our capital expenditure programs. Our lenders review the credit facility each year and determine if they will extend for another year. The credit facility matures on July 1, 2009 and, although we have no reason to believe that we will be unable to extend the credit facility, in the event that the facility is not extended before July 1, 2009, indebtedness under the facility will be repayable at that date. There is also a risk that the credit facility will not be renewed for the same amount or on the same terms. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the NPI and interest on the Notes and net income. Furthermore, any of these events could affect our ability to fund ongoing operations.

We currently have US$179.7 million of 9.625% senior subordinated notes due July 15, 2010 and US$247,000 of 10.5% senior subordinated notes due February 15, 2011. We also have $10.4 million of Convertible Debentures outstanding which are convertible at the option of the holder at any time into fully paid Trust Units at a conversion price of $14.75 per unit and mature on December 31, 2010. We intend to partially fund these debt maturities with our existing credit facility; however, we are subject to limitations on the amounts we can draw on our credit facility in order to repay the senior subordinated notes and the Convertible Debentures. The maximum amount we may draw for any such repayments is 20% of the amount of our credit facility and this amount is reduced to nil if the amount drawn on our credit facility exceeds 75% of the amount of such facility. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations and distribute cash.

We are required to comply with covenants under the credit facility. In the event that we do not comply with covenants under the credit facility, our access to capital could be restricted or repayment could be required on an accelerated basis by our lenders, and the ability to make distributions to our Unitholders may be restricted. The lenders have security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as breach of our financial covenants, the lender may foreclose on or sell our working interests in our properties.

From time to time we may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. We are not restricted in the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Amounts paid in respect of interest and principal on debt may reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants in the agreements with our lenders may also limit distributions. Although we believe the credit facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our capital expenditure program, or that we will be able to obtain additional funds.

The weakened global economic situation may affect our access to capital markets

Commercial credit market disruptions have resulted in a tightening of credit markets worldwide. Liquidity in the global credit market has been severely contracted by these market disruptions, making it costly to obtain new lines of credit or to refinance existing debt. The effects of these disruptions are widespread and difficult to quantify, and it is impossible to predict when the global credit market will improve or when the credit contraction will stop. As a result of the ongoing credit market turmoil, we will have restricted access to capital and increased borrowing costs. Although our business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash flow from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result.

Alternatively, we may issue additional Trust Units from treasury at prices which may result in a decline in production per Trust Unit and reserves per Trust Unit or may wish to borrow to finance significant acquisitions or development projects to accomplish our long term objectives on less than optimal terms or in excess of our optional capital structure.

We believe that cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to Unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary, and we have the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices. However, if cash flow from operations is lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties or a decrease in distributions.

The weakened global economy may expose us to increased third party credit risk

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. We manage this credit risk by entering into sales contracts with only creditworthy entities and reviewing its exposure to individual entities on a regular basis. However, in the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

We may be impacted by recent federal tax changes for income trusts and corporations

The SIFT Rules will apply a tax at the trust level on distributions of certain income from trusts, such as us, at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the unitholders. The SIFT Rules will result in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact the amount of cash flow from operations available for distributions to Unitholders.

Generally, there will be a four year transition period for an existing SIFT entity, such as us, and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded.

While the normal growth restrictions are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions. The SIFT tax has reduced the value of the Trust Units, which has increased the cost to us of raising capital in the public capital markets. In addition, management believes that the SIFT Rules: (a) substantially eliminate the competitive advantage that we and other Canadian energy trusts enjoyed relative to our corporate peers in raising capital in a tax-efficient manner, and (b) places us and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships which will continue to not be subject to entity level taxation. The new legislation also makes the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the SIFT Rules.

No assurance can be provided that the SIFT tax will not apply to us prior to January 1, 2011, or that the legislation will not be further changed in a manner which affects us and our Unitholders. See "*— Risks Associated with Governme Regulation – Our revenues are affected by changes in regulations*".

We may have delays in cash receipt

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses.

We are affected by political events

The marketability and price of oil and natural gas that may be acquired or discovered by us are and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our cash flow from operations.

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the object of a terrorist attack, it could have a material adverse effect on our financial condition. We do not carry insurance to protect against potential losses from acts of terrorism.

Risks Relating to our Operations

Exploitation and development may not result in commercially productive reserves

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by us. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Distributions may be affected by operating costs and production declines

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by us and, therefore, may reduce distributions to our Unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of our operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distribution to our Unitholders.

Our business involves numerous operating hazards, and we are not fully insured against all of them

Our operations are subject to all of the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, sour gas releases and spills, blow-outs, craterings and fires, all of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance policies in place, in such amounts as we consider adequate to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce the income receivable by us under the NPI.

Project delays may delay expected revenues from operations

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we may be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that we produce.

Drilling equipment availability and access may be restricted

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

We are affected by seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Reserves figures are only estimates and may require revision

Although we, together with Sproule, have carefully prepared the reserves figures included in this Annual Information Form and believe that the methods of estimating reserves have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and the future cash flows attributed to such reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net revenues therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves or estimates of resources attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary.

Estimates of proved reserves that may be developed and produced in the future are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from reserves will vary from the reserves estimates contained in the Sproule Report summarized in this Annual Information Form, and such variations could be material. The estimates in the Sproule Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Sproule Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the engineering reports summarized in this Annual Information Form.

The reserves and recovery information contained in the Sproule Report are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by Sproule. The Sproule Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the Sproule Report, the present value of estimated future net cash flows for our reserves would be reduced and the reduction could be significant.

Our reserves may become depleted

We conduct limited exploration activities for oil and natural gas reserves. Instead, we add to our oil and natural gas reserves primarily through development and acquisitions. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We also distribute a significant proportion of our cash flow from operations to Unitholders rather than reinvesting it in reserves additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. To the extent that we use cash flow from operations to finance capital expenditures or property acquisitions, the level of cash flow from operations available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline. These events may result in a reduction in the value of Trust Units and in a reduction in cash flow from operations available for distributions to Unitholders.

Distributions may be affected by capital expenditures

The timing and amount of capital expenditures will directly affect the amount of cash flow from operations available for distribution to Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made. In addition, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired.

We are dependent on our operators and other third parties to produce and market our property

Other companies operate some of the assets in which we have an interest. Continuing production from a property, and, to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. As a result, we have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. In addition, payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Our return on assets operated by others will therefore depend upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

We face competition from competitors with greater resources

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts and other companies in the oil and gas industry, who are competing for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it is difficult to acquire reserves on beneficial terms. We also compete for reserves acquisitions and undeveloped land with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than we do.

We compete with other oil and gas entities to hire and retain skilled personnel necessary for running our daily operations, including the execution of our annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

Our permitted investments may be risky

An investment in the Trust should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy-related income trusts, companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of Trust Units could be affected by adverse changes in the market values of such investments.

Risks Associated with Government Regulation

We are affected by federal and provincial laws and regulations relating to the environment

Nearly all aspects of our operations are subject to a variety of federal, provincial and local laws and regulations, including laws and regulations relating to the protection of the environment and the operation, maintenance, abandonment and reclamation of sites and wells, which may be amended from time to time to impose higher standards and potentially more costly obligations on us. Environmental assessments, permits and regulatory approvals are required before initiating most new major projects or undertaking significant changes to existing operations. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders in respect of us or our properties. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. We provide for the necessary amounts in our annual capital budget for the purpose of funding our currently estimated future environmental and reclamation obligations based on our current knowledge.

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production, a reduction of product demand, a material increase in the costs of production, development or exploration activities or otherwise adversely affect our business, financial condition, results of operations and prospects. Environmental legislation is evolving in a manner expected to 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 or results of operations. There can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations. See "*Industry Conditions — Environmental Regulation*".

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases which will require us to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Our management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets or taxes based upon emissions. There has been much public debate with respect to Canada's ability to meet emission targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Our revenues are affected by changes in regulations

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. See "*Industry Conditions*" and "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*". Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase our costs, any of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, we will require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake.

Our status as a mutual fund trust may be changed or affected by changes in legislation

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders. Tax authorities having jurisdiction over us or the Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practises to our detriment or the detriment of our Unitholders**.**

There can be no assurance that the treatment of mutual fund trusts will not be changed in a manner adversely affecting Unitholders. If we cease to qualify as a "mutual fund trust" under the Tax Act, the Trust Units will cease to be qualified investments for registered retirement savings plans ("**RRSPs**"), registered education savings plans ("**RESPs**"), deferred profit sharing plans ("**DPSPs**"), registered disability savings plans ("**RDSPs**"), tax free savings accounts ("**TFSAs**") and registered retirement income funds ("**RRIFs**").

We expect to continue to qualify as a mutual fund trust for purposes of the Tax Act. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. We may not be able to take steps necessary to ensure that we maintain our mutual fund trust status. Even if we are successful in taking such measures, these measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada (as defined in the Tax Act). There can be no assurance that such circumstances would not have a material adverse affect on the market price of the Trust Units.

Should the status of us as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if we ceased to be a mutual fund trust.

- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

- Trust Units would cease to be a qualified investment for RRSPs, RESPs, DPSPs, RDSPs, TFSAs and RRIFs. Where, at the end of a month, a RRSP, DPSP, RESP or RRIF holds Trust Units that cease to be a qualified investment, the plan must, in respect of that month, pay a tax equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the plan. Trusts governed by RRSPs, RDSPs, TFSAs or RRIFs which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are not qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment is included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the Canada Revenue Agency. The holder of a RDSP or TFSA which holds Trust Units that are not qualified investments will be subject to tax equal to 50% of the fair market value of the Trust Units.

In addition, we may take certain measures in the future to the extent we believe necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Tax Act. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Non-resident Unitholders* ".

We have non-resident ownership restrictions of our Trust Units

We intend to comply with the requirements under the Tax Act for "unit trusts" and "mutual fund trusts" at all relevant times such that we maintain our status of a unit trust and a mutual fund trust for purposes of the Tax Act. In this regard, we may, from time to time, among other things, take all necessary steps to monitor our activities and ownership of the Trust Units. If at any time we become aware that our activities and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten our status under the Tax Act as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in our opinion to maintain our status as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by us, or the transfer by any Unitholder, of Trust Units to a non-resident. See " *Additional Information Respecting Baytex Energy Trust – Trust Indenture – Non-Resident Unitholders*" and " *Risk Factors – Risks Associated with Government Regulation – Our status as a mutual fund trust may be changed or affected by changes in legislation* ".

Risks Associated with Acquisitions and Expansion

We may not realize anticipated benefits of acquisitions and dispositions or manage our growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of our operations. The integration of an acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that management can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Acquisitions of resource issuers and resource assets will be based in large part upon engineering and economic assessments made by independent engineers. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies, which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. In particular, the prices of and markets for resource products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty, which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based upon reports by a firm of independent engineers other than the firm that we use for our year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm we use. Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received by us.

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

We may expand our operations

Our operations and expertise are currently primarily focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin, although we have recently expanded into the United States. In the future, we may acquire oil and gas properties outside of these geographic areas. In addition, the terms of the Trust Indenture do not limit us to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

Management Risks

We are dependant on Baytex management

We are a limited purpose trust and are entirely dependent upon the operations and assets of Baytex through our ownership, directly and indirectly, of securities of Baytex, including the common shares of Baytex, the Notes and the NPI. Accordingly, our ability to pay distributions to Unitholders is dependent upon the ability of Baytex to meet its interest, principal, dividend and other distribution obligations on the securities of Baytex and to pay the NPI. Baytex's income is received from the production of oil and natural gas from its Canadian resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. If the oil and natural gas reserves associated with Baytex's resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of Baytex to meet its obligations to us and our ability to pay distributions to Unitholders may be adversely affected.

Our directors and officers may have conflicts

Our directors and officers are engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, they may become subject to conflicts of interest. The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director will disclose his interest in such contract or agreement and will refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the *Business Corporations Act* (Alberta). To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

As at the date hereof, we are not aware of any existing or potential material conflicts of interest between us and a director or officer of ours.

Capital Risks

Our net asset value will vary from time to time

Our net asset value from time to time will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater or less than our net asset value.

We may issue additional Trust Units

In the normal course of making capital investments to maintain and expand our oil and gas reserves, additional Trust Units may be issued from treasury which may result in a decline in production and reserves per Trust Unit. Additionally, from time to time we may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. We may also make future acquisitions or enter into financings or other transactions involving the issuance of securities which may be dilutive. To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. Management believes that the SIFT Rules will substantially eliminate the competitive advantage that we and other energy trusts have enjoyed relative to our industry competitors in raising capital in a tax-efficient manner. See "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations* " and " *Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trust and corporations*". To the extent that we are required to use cash flow from operations to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash flow from operations available for distribution to Unitholders will be reduced.

Risks Associated with our Structure as a Trust

Our Trust Units are not shares

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Baytex. The Trust Units represent a fractional interest in us. Corporate law does not govern us and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. Our sole assets will be the NPI and other investments in securities of our operating entities. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not be equal to or greater than the initial capital investment.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that act or any other legislation. Furthermore, we are not a trust company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

Our Trust Units have a limited redemption right

Unitholders have a limited right to require a repurchase of their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investments. Notes or Redemption Notes (as defined in the Trust Indenture) which may be distributed *in specie* to Unitholders in connection with redemption will not be listed on any stock exchange and no established market is expected to develop for such Notes or Redemption Notes. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. Cash redemptions are subject to limitations. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Redemption Right* ".

Trust Units will have no value when reserves from our properties can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Consequently, distributions represent a blend of *return of* Unitholders initial investment and a *return on* Unitholders initial investment.

Our Unitholders may not have limited liability

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with us or our obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against us.

We allocate all of our income

Pursuant to the provisions of the Trust Indenture, all income earned by us in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period, they will be allocated such income but will dispose of their right to receive such distribution.

Our expenses and other deductions may be challenged by taxing authorities

Generally, oil and gas income trusts involve significant amounts of inter-company debt, royalties or similar instruments, generating substantial interest expense or other deductions which serve to reduce taxable income and income tax payable. There can be no assurance that the taxation authorities will not seek to challenge the amount of our interest expense and other deductions. If such a challenge were to succeed against us, it could materially adversely affect the amount of cash flow received by us and, therefore, may reduce distributions to our unitholders.

Certain Risks for United States and other non-resident Unitholders

The ability of United States and other non-resident investors to enforce civil remedies may be limited

We are a trust organized under the laws of Alberta, Canada, and our principal place of business is in Canada. All of the directors and officers of Baytex are residents of Canada and most of the experts who provide services to us (such as our auditors and our independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and our assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgments of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

There are differences in reporting practices in Canada and the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, and we do not estimate our reserves using prices and costs held constant at the effective date of the reserve report.

We include in this Annual Information Form estimates of our proved and proved plus probable reserves. The SEC generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

United States and other non-resident Unitholders may be subject to additional taxation

The Tax Act and the tax treaties between Canada and other countries may impact withholding or other taxes on the cash distributions or other property paid by us to Unitholders who are not residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15 percent withholding tax is applied to distributions made to non-resident unitholders.

Non-resident Unitholders are subject to foreign exchange risk

Our distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar weakens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

We are an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture. We were established to, among other things:

- invest in shares of Baytex and acquire the common shares of Baytex and the Notes pursuant to the plan of arrangement which was completed on September 2, 2003;
- acquire the NPI under the NPI Agreement;
- acquire or invest in other securities of Baytex and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts;
- dispose of any part of the property of the Trust, including, without limitation, any securities of Baytex;
- temporarily hold cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making other permitted investments under the Trust Indenture, pay amounts payable by the Trust in connection with the redemption of any Trust Units, and make distributions to Unitholders; and
- pay costs, fees and expenses associated with the foregoing purposes or incidental thereto.

We are prohibited from acquiring any investment which (a) would result in the cost amount to us of all "foreign property" (as defined in the Tax Act) which is held by us to exceed the amount prescribed by applicable tax laws or (b) would result in us not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

Our principal undertaking is to issue Trust Units and other securities and to acquire and hold net profits interests, royalties and other interests. Baytex and our operating subsidiaries carry on the business of acquiring and holding interests in oil and natural gas properties and assets related thereto. Cash flow from these properties is flowed from our operating subsidiaries to us by way of interest payments and principal repayments on the Notes and through NPI payments.

The Trustee may declare payable to Unitholders all or any part of our income. Currently the only income we receive is from the interest and principal payments received on the Notes and NPI payments. We make monthly cash distributions to Unitholders on our income, after expenses, if any, and any cash redemptions of Trust Units. Cash distributions are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month. Our current distribution practice targets the use of between 50 to 60 percent of our available cash flow from operations for capital expenditures to fund both exploration and development expenditures and minor property acquisitions, but excludes major acquisitions.

Pursuant to various agreements with Baytex's lenders, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under Baytex's credit facilities or upon a material borrowing base shortfall or default.

Baytex's senior subordinated notes also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution to us and the payment of interest or principal on subordinated debt owed to us. Baytex is restricted from making any restricted payments, including distributions to us, if a default or event of default under the note indenture governing the senior subordinated notes has occurred and is continuing. If no such default or event of default has occurred and is continuing, Baytex may make a distribution to us provided at the time either (A) (i) its ratio of consolidated debt to consolidated cash flow from operations does not exceed 3 to 1, (ii) its fixed charge coverage ratio for the preceding four fiscal quarters is greater than 2.5 to 1 and (iii) the aggregate of all restricted payments declared or made after July 9, 2003 does not exceed the sum of 80 percent of the consolidated cash flow from operations accrued on a cumulative basis since July 9, 2003 plus the net cash proceeds received by us from the issuance of deeply subordinated intercompany debt or the receipt of capital contributions from the Trust plus net proceeds received by Baytex from the issuance of and upon conversion of debt and other securities or (B) the aggregate amount of all restricted payments declared or made after July 9, 2003 does not exceed the sum of permitted restricted payments not previously made plus US$30,000,000.

Baytex Energy Ltd.

Baytex Energy Ltd. is amalgamated under the *Business Corporations Act* (Alberta) and is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production in Canada. We are the sole common shareholder of Baytex.

The head office of Baytex is located at Suite 2200, 205 – 5 th Avenue S.W., Calgary, Alberta, T2P 2V7 and its registered office is located at Suite 1400, 350 – 7 th Avenue S.W., Calgary, Alberta T2P 3N9.

NPI

We are a party to the NPI Agreement with Baytex pursuant to which we have the right to receive a NPI on petroleum and natural gas rights held by Baytex from time to time. Pursuant to the terms of the NPI Agreement, we are entitled to a payment from Baytex for each month equal to the amount by which 99 percent of the gross proceeds from the sale of production attributable to such property interests for such month exceed 99 percent of certain deductible costs for such period. Baytex is entitled to set off amounts reimbursable to it against NPI payments payable by Baytex. The term of the NPI Agreement is for so long as there are petroleum and natural gas rights to which the NPI applies.

Notes

A Note was issued by Baytex to us under the Note Indenture in connection with the plan of arrangement completed on September 2, 2003. The Note is unsecured, payable on demand and bears interest from the date of issue at an interest rate equal to 12 percent per annum. Interest is payable for each month during the term on the 10th day of the month following such month.

Although Baytex is permitted to make payments against the principal amount of the Notes outstanding from time to time without notice or bonus, Baytex is not required to make any payment in respect of principal until December 31, 2033, subject to extension in limited circumstances.

In contemplation of the possibility that additional Notes may be distributed to Unitholders upon the redemption of their Trust Units, the Note Indenture provides that if persons other than us (the " **Non-Fund Holders**") own Notes having a aggregate principal amount in excess of $1,000,000, either we or the Non-Fund Holders will be entitled, among other things, to require the trustee appointed under the Note Indenture to exercise the powers and remedies available under the Note Indenture upon an event of default and either we or the Non-Fund Holders may provide consents, waivers or directions relating generally to the variance of the Notes Indenture and the rights of noteholders. The Note Indenture allows Baytex the flexibility to delay payments of interest or principal otherwise due to us while payment is made to the Non-Fund Holders, and to allow the Non-Fund Holders to be paid out before us. Any delayed payments will be due five days after demand.

From time to time we advance funds to our controlled entities which are evidenced by promissory notes. The terms of the notes are set at the time of issue. All of these advances are subordinate to all senior indebtedness to our senior lenders.

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2008. The statement is effective as of December 31, 2008 and the preparation date of the statement by Sproule is March 4, 2009. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Sproule in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2008 as contained in the Sproule Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any hedging activities. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Sproule was engaged by us to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. See also "*Definitions and Other Notes to Reserve Data Tables*" below.

Our reserves are located in Canada, specifically in the provinces of Alberta, British Columbia and Saskatchewan, and in the United States, specifically in the states of North Dakota and Wyoming.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. The recovery and reserve estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors*".

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM OIL		HEAVY OIL		BITUMEN	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	6,703.4	4,723.5	28,430.2	23,487.2	-	-
Developed Non-Producing	705.0	507.1	20,922.5	17,139.5	-	-
Undeveloped	3,673.5	2,823.9	37,584.1	30,712.2	-	-
TOTAL PROVED	11,081.9	8,054.5	86,936.9	71,338.9	-	-
PROBABLE	5,461.8	3,592.3	36,652.9	29,950.5	2,463.7	2,082.8
TOTAL PROVED PLUS PROBABLE	16,543.7	11,646.9	123,589.8	101,289.3	2,463.7	2,082.8

	NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:						
Developed Producing	87,540.0	69,886.0	2,756.0	2,100.2	52,479.7	41,958.6
Developed Non-Producing	16,606.9	11,355.8	594.2	432.8	24,989.5	19,972.0
Undeveloped	13,813.1	11,126.8	375.4	274.5	43,935.1	35,665.1
TOTAL PROVED	117,960.0	92,368.6	3,725.5	2,807.5	121,404.4	97,595.7
PROBABLE	55,016.0	40,778.9	1,846.3	1,381.2	55,593.8	43,803.3
TOTAL PROVED PLUS PROBABLE	172,976.0	133,147.5	5,571.8	4,188.7	176,998.2	141,398.9

UNITED STATES

	LIGHT AND MEDIUM OIL		HEAVY OIL		BITUMEN	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	1,190.8	1,090.6	-	-	-	-
Developed Non-Producing	196.3	159.1	-	-	-	-
Undeveloped	2,560.6	2,074.3	-	-	-	-
TOTAL PROVED	3,947.6	3,324.0	-	-	-	-
PROBABLE	5,322.0	4,333.1	-	-	-	-
TOTAL PROVED PLUS PROBABLE	9,269.6	7,657.1	-	-	-	-

	NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:						
Developed Producing	186.0	172.5	-	-	1,221.8	1,119.3
Developed Non-Producing	198.0	160.3	-	-	229.2	185.8
Undeveloped	1,633.0	1,322.6	-	-	2,832.7	2,294.8
TOTAL PROVED	2,017.0	1,655.4	-	-	4,283.7	3,599.9
PROBABLE	3,209.8	2,600.1	-	-	5,857.0	4,766.5
TOTAL PROVED PLUS PROBABLE	5,226.8	4,255.6	-	-	10,140.7	8,366.3

TOTAL

	LIGHT AND MEDIUM OIL		HEAVY OIL		BITUMEN	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	7,894.2	5,814.1	28,430.2	23,487.2	-	-
Developed Non-Producing	901.3	666.2	20,922.5	17,139.5	-	-
Undeveloped	6,234.1	4,898.2	37,584.1	30,712.2	-	-
TOTAL PROVED	15,029.5	11,378.5	86,936.9	71,338.9	-	-
PROBABLE	10,783.8	7,925.4	36,652.9	29,950.5	2,463.7	2,082.8
TOTAL PROVED PLUS PROBABLE	25,813.3	19,304.0	123,589.8	101,289.3	2,463.7	2,082.8

	NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:						
Developed Producing	87,726.0	70,058.5	2,756.0	2,100.2	53,701.5	43,077.9
Developed Non-Producing	16,804.9	11,516.1	594.2	432.8	25,218.7	20,157.8
Undeveloped	15,446.1	12,449.4	375.4	274.5	46,767.8	37,959.9
TOTAL PROVED	119,977.0	94,024.0	3,725.5	2,807.5	125,688.1	101,195.6
PROBABLE	58,225.8	43,379.0	1,846.3	1,381.2	61,450.8	48,569.8
TOTAL PROVED PLUS PROBABLE	178,202.8	137,403.1	5,571.8	4,188.7	187,138.9	149,765.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADA	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,570,813	1,328,371	1,153,750	1,025,230	927,159
Developed Non-Producing	934,865	671,482	504,487	392,656	314,426
Undeveloped	1,442,200	1,028,458	761,663	580,949	453,470
TOTAL PROVED	3,947,878	3,028,311	2,419,900	1,998,835	1,695,054
PROBABLE	2,143,969	1,385,887	965,439	711,673	548,133
TOTAL PROVED PLUS PROBABLE	6,091,847	4,414,198	3,385,339	2,710,508	2,243,188
UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	73,466	41,862	28,942	22,302	18,310
Developed Non-Producing	10,285	4,829	2,538	1,366	672
Undeveloped	128,892	49,242	17,650	2,469	(5,885)
TOTAL PROVED	212,643	95,933	49,130	26,137	13,096
PROBABLE	392,809	118,743	44,385	16,399	3,423
TOTAL PROVED PLUS PROBABLE	605,452	214,676	93,515	42,536	16,519
TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,644,279	1,370,233	1,1182,692	1,047,532	945,469
Developed Non-Producing	945,150	676,311	507,025	394,022	315,098
Undeveloped	1,571,092	1,077,700	779,313	583,418	447,585
TOTAL PROVED	4,160,521	3,124,244	2,469,030	2,024,972	1,708,150
PROBABLE	2,536,778	1,504,630	1,009,824	728,072	551,556
TOTAL PROVED PLUS PROBABLE	6,697,299	4,628,874	3,478,854	2,753,044	2,259,707

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADA	**AFTER INCOME TAXES DISCOUNTED AT (%/year)**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,506,201	1,286,143	1,125,215	1,005,386	913,014
Developed Non-Producing	701,152	508,179	386,019	304,062	246,499
Undeveloped	1,108,930	791,187	586,072	446,926	348,587
TOTAL PROVED	3,316,283	2,585,509	2,097,305	1,756,374	1,508,100
PROBABLE	1,609,133	1,043,946	731,738	543,614	422,416
TOTAL PROVED PLUS PROBABLE	4,925,416	3,629,456	2,829,044	2,299.989	1,930,516
UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	42,936	24,612	17,064	13,173	10,830
Developed Non-Producing	5,983	2,719	1,314	574	123
Undeveloped	74,983	27,148	7,636	(2,063)	(7,595)
TOTAL PROVED	123,902	54,478	26,015	11,685	3,358
PROBABLE	228,881	67,090	22,422	5,270	(2,799)
TOTAL PROVED PLUS PROBABLE	352,784	121,568	48,436	16,955	559
TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,549,137	1,310,755	1,142,279	1,018,559	923,844
Developed Non-Producing	707,135	510,898	387,333	304,636	246,622
Undeveloped	1,183,913	818,335	593,708	444,863	340,992
TOTAL PROVED	3,440,185	2,639,987	2,123,320	1,768,059	1,511,458
PROBABLE	1,838,014	1,111,036	754,160	548,884	419,617
TOTAL PROVED PLUS PROBABLE	5,278,200	3,751,024	2,877,480	2,316,944	1,931,075

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

TOTAL PROVED RESERVES	**REVENUE ($000s)**	**ROYALTIES ($000s)**	**OPERATING COSTS ($000s)**	**DEVELOP-MENT COSTS ($000s)**	**WELL ABANDON-MENT COSTS ($000s)**	**FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)**	**INCOME TAXES ($000s)**	**FUTURE NET REVENUE AFTER INCOME TAXES ($000s)**
Canada	7,759,971	1,466,630	1,852,826	384,973	107,664	3,947,878	631,595	3,316,284
United States	460,624	136,783	54,862	56,336	-	212,643	88,741	123,902
Total	8,220,595	1,603,413	1,907,688	441,309	107,664	4,160,521	720,336	3,440,186
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	11,876,380	2,312,969	2,810,466	510,282	150,815	6,091,848	1,166,431	4,925,417
United States	1,220,099	369,232	119,050	126,365	-	605,452	252,668	352,784
Total	13,096,479	2,682,201	2,929,516	636,647	150,815	6,697,300	1,419,099	5,278,201

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe) [1]
CANADA			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	233,555	26.53
	Heavy Oil (including solution gas and other by-products)	1,749,549	24.31
	Bitumen	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	436,796	25.96
	Total Canada	2,419,900	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	334,871	26.13
	Heavy Oil (including solution gas and other by-products)	2,427,574	19.58
	Bitumen	14,034	6.74
	Natural Gas (including by-products but excluding natural gas from oil wells)	608,860	24.99
	Total Canada	3,385,339	
UNITED STATES			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	50,194	13.99
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	(1,064)	(81.83)
	Total United States	49,130	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	94,579	11.32
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	(1,064)	(81.83)
	Total United States	93,515	
TOTAL			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	283,749	22.90
	Heavy Oil (including solution gas and other by-products)	1,749,549	24.31
	Bitumen	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	435,732	25.88
	Total	2,469,030	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	429,450	20.29
	Heavy Oil (including solution gas and other by-products)	2,427,575	19.58
	Bitumen	14,034	6.74
	Natural Gas (including by-products but excluding natural gas from oil wells)	607,796	24.93
	Total	3,478,855	

Note:

(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above under the subheading " *Disclosure of Reserves Data*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of " *Economic Assumptions*" below).

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   (c) "Economic Assumptions" will be the forecast prices and costs used in the estimate.

   Development and Production Status

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. "**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

5. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

8. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. "**Forecast Prices and Costs**"

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Baytex is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2008, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2008

	OIL			NATURAL GAS		
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	AECO-C ($Cdn/MMbtu)	INFLATION RATES [1] %/year	EXCHANGE RATE [2] ($US/$Cdn)
Historical						
2004	41.42	52.91	30.40	6.87	1.4	0.770
2005	56.46	69.29	34.35	8.58	1.3	0.826
2006	66.09	73.30	43.32	7.16	1.5	0.882
2007	72.27	77.06	44.77	6.65	2.0	0.935
2008 Est.	99.59	102.85	76.32	8.15	1.0	0.943
Forecast						
2009	53.73	65.35	47.05	6.82	2.0	0.800
2010	63.41	72.78	54.58	7.56	2.0	0.850
2011	69.53	79.95	59.96	7.84	2.0	0.850
2012	79.59	86.57	67.53	8.38	2.0	0.900
2013	92.01	94.97	74.08	9.20	2.0	0.950
Thereafter.		Various escalation rates				

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

Weighted average prices realized by us for the year ended December 31, 2008, excluding hedging activities, were $7.92/Mcf for natural gas, $88.92/bbl for light oil and NGL and $65.22/bbl for heavy oil.

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
CANADA	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2007	10,037.2	5,294.7	15,331.9	85,068.7	37,392.6	122,461.3
Extensions	-	-	-	409.5	333.9	743.4
Improved Recovery	467.3	247.3	714.6	3,305.7	7,380.6	10,686.3
Technical Revisions	2,016.9	(329.9)	1,687.0	6,269.3	(8,819.0)	(2,549.7)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	590.5	236.4	826.9	81.0	86.4	167.4
Dispositions	-	-	-	-	-	-
Economic Factors	36.6	13.3	49.9	486.8	263.3	750.1
Production	(2,066.6)	-	(2,066.6)	(8,721.7)	-	(8,721.7)
December 31, 2008	11,081.9	5,461.8	16,543.7	86,936.9	36,652.9	123,589.8

CANADA	BITUMEN			ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	-	-	-	103,969	44,888	148,857
Extensions	-	-	-	248	393	641
Improved Recovery	-	2,463.7	2,463.7	6,660	3,022	9,682
Technical Revisions	-	-	-	(6,053)	(7,620)	(13,673)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	31,945	13,782	45,727
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	1,233	551	1,784
Production	-	-	-	(20,042)	-	(20,042)
December 31, 2008	-	2,463.7	2,463.7	117,960	55,016	172,976

CANADA	NATURAL GAS LIQUIDS			OIL EQUIVALENT		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2007	3,603.4	1,869.6	5,473.0	116,037.5	52,038.2	168,075.7
Extensions	32.3	6.1	38.4	483.2	405.5	888.7
Improved Recovery	166.0	66.7	232.7	5,049.1	10,661.9	15,711.0
Technical Revisions	(503.8)	(563.2)	(1,067.0)	6,773.6	(10,982.1)	(4,208.6)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	1,031.9	444.9	1,476.8	7,027.5	3,064.8	10,092.3
Dispositions	-	-	-	-	-	-
Economic Factors	35.3	22.2	57.5	764.3	390.6	1,154.9
Production	(639.6)	-	(639.6)	(14,768.3)	-	(14,768.3)
December 31, 2008	3,725.5	1,846.3	5,571.8	121,404.5	55,594.0	176,998.4

UNITED STATES	LIGHT AND MEDIUM OIL			ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved Recovery	-	3,367.9	3,367.9	96	2,099	2,195
Technical Revisions	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	4,013.9	1,954.1	5,968.0	1,935	1,111	3,046
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(66.3)	-	(66.3)	(15)	-	(15)
December 31, 2008	3,947.6	5,322.0	9,269.6	2,016	3,210	5,226

			OIL EQUIVALENT		
UNITED STATES	*60;*		Proved (Mboe)	Probable (Mboe)	Pro P Prob (Mb
December 31, 2007			-	-	
	Extensions		-	-	
	Improved Recovery	60;	16.0	3,717.7	3,7
	Technical Revisions	60;	-	-	
	Discoveries	60;	-	-	
	Acquisitions	60;	4,336.4	2,139.3	6,4
	Dispositions	60;	-	-	
	Economic Factors	60;	-	-	
	Production	60;	(68.8)	-	(6
December 31, 2008		**60;**	4,283.6	5,857.0	10,

	LIGHT AND MEDIUM OIL			HEAVY OIL		
TOTAL	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2007	10,037.2	5,294.7	15,331.9	85,068.7	37,392.6	122,461.3
Extensions	-	-	-	409.5	333.9	743.4
Improved Recovery	467.3	3,615.2	4,082.5	3,305.7	7,380.6	10,686.3
Technical Revisions	2,016.9	(329.9)	1,687.0	6,269.3	(8,819.0)	(2,549.7)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	4,604.4	2,190.5	6,794.9	81.0	86.4	167.4
Dispositions	-	-	-	-	-	-
Economic Factors	36.6	13.3	49.9	486.8	263.3	750.1
Production	(2,132.8)	-	(2,132.8)	(8,721.7)	-	(8,721.7)
December 31, 2008	15,029.5	10,783.8	25,813.3	86,936.9	36,652.9	123,589.8

	BITUMEN			ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS		
TOTAL	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	-	-	-	103,969	44,888	148,857
Extensions	-	-	-	248	393	641
Improved Recovery	-	2,463.7	2,463.7	6,756	5,121	11,877
Technical Revisions	-	-	-	(6,053)	(7,620)	(13,673)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	33,880	14,893	48,773
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	1,233	551	1,784
Production	-	-	-	(20,057)	-	(20,057)
December 31, 2008	-	2,463.7	2,463.7	119,976	58,226	178,202

	NATURAL GAS LIQUIDS			OIL EQUIVALENT		
TOTAL	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2007	3,603.4	1,869.6	5,473.0	116,037.5	52,038.2	168,075.7
Extensions	32.3	6.1	38.4	483.2	405.5	888.7
Improved Recovery	166.0	66.7	232.7	5,065.1	14,379.6	19,444.7
Technical Revisions	(503.8)	(563.2)	(1,067.0)	6,773.6	(10,982.1)	(4,208.6)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	1,031.9	444.9	1,476.8	11,363.8	5,204.1	16,567.9
Dispositions	-	-	-	-	-	-
Economic Factors	35.3	22.2	57.5	764.3	390.6	1,154.9
Production	(639.6)	-	(639.6)	(14,837.0)	-	(14,837.0)
December 31, 2008	3,725.5	1,846.3	5,571.8	125,688.1	61,451.0	187,139.0

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped 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.

Approximately 50 to 60 percent of our expected cash flow from operations is available for capital expenditures related to exploration and development activities and the balance is distributed to our Unitholders. We allocate development capital to our assets in an efficient and disciplined process. We reduce risk by technically assessing the results of each of our development programs before committing additional capital. This disciplined approach to investing in development means that in most cases it will take longer than two years to develop our proved undeveloped and probable undeveloped reserves. We plan to develop the majority of our proved undeveloped reserves over the next 8 years and probable undeveloped reserves over the next 10 years.

Our capital spending on development projects is budgeted annually for each of our business units. Once a development program is executed, we measure and analyze the results of that capital investment, make any changes to the program that are necessary, and then repeat the process until all economic oil and gas reserves are developed. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent four financial years and, in the aggregate, before that time.

	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Natural Gas Gross (MMcf)		NGLs Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior	1,768.9	1,768.9	19,898.0	19,898.0	7,800	7,800	384.6	384.6
2005	197.7	1,660.2	9,077.7	28,722.2	11,318	19,027	424.0	615.1
2006	–	1,492.7	7,569.9	30,085.7	951	17,466	24.3	629.9
2007	2,112.0	3,574.1	9,833.3	38,168.8	2,559	15,587	55.6	378.4
2008	2,830.6	6,234.1	2,175.9	37,584.1	3,234	15,446	37.3	375.4

Sproule assigned a total of 451 well locations to the proved undeveloped reserve category. 358 of these wells are located on our Canadian heavy oil producing properties. There were no proved undeveloped bitumen reserves assigned by Sproule. The 358 heavy oil proved undeveloped locations are scheduled to be drilled over the next six years. 66 of the total proved undeveloped locations are within our Canadian conventional oil and gas producing properties. These conventional oil and gas well locations are scheduled to be drilled over the next six years. The remaining 27 proved undeveloped wells are located in the United States within Divide County, North Dakota. This is a conventional, light oil development project area for Baytex. The wells in North Dakota are scheduled to be drilled over the next four years.

It would not be prudent from both a financial and technical perspective for us to develop all of our proved undeveloped reserves over the next two years. Our operating budget allocates between 50 to 60 percent of expected cash flow from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 120 based on 2008 spending and activity levels. Not all of the development wells that we drill in any given year are contained within the Sproule defined proved undeveloped inventory. At our current pace of investment and drilling it will take approximately five to six years to develop all the currently identified proved undeveloped reserves in the Sproule report.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent four financial years and, in the aggregate, before that time.

	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Natural Gas Gross (MMcf)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	673.3	673.3	11,351.5	11,351.5	5,304	5,304
2005	19.6	523.7	3,209.0	13,621.9	8,555	12,774
2006	2.0	524.6	4,556.5	17,591.8	291	8,451
2007	1,040.8	1,557.5	3,804.1	20,410.1	5,476	10,832
2008	5,179.3	6,404.7	4,833.2	20,634.7	5,467	13,587

	NGLs Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	61.8	61.8	–	–
2005	608.0	608.0	–	–
2006	1.4	302.6	–	–
2007	513.3	615.7	–	–
2008	76.3	362.2	2,463.7	2,463.7

Sproule assigned a total of 249 well locations to the probable undeveloped reserve category, of which 178 are located within our Canadian primary heavy oil producing properties. These 178 heavy oil locations are scheduled to be drilled over the next ten years. Ten of these probable undeveloped locations are thermal heavy oil wells (bitumen) located in the Seal area of Alberta. Sproule has scheduled these thermal wells to be drilled by the end of 2013. Twenty-three of these probable undeveloped locations are located on our Canadian conventional oil and gas producing properties. These conventional oil and gas locations are scheduled to be drilled over the next ten years. The remaining 38 probable undeveloped wells are located in the United States within Divide County, North Dakota. This is a conventional light oil development project area for Baytex. These wells in North Dakota are scheduled to be drilled over the next five years.

For the same reasons given above, we will not develop all of our probable undeveloped reserves over the next two years. Our operating budget allocates between 50 to 60 percent of our expected cash flow from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 120 based on 2008 spending and activity levels. Not all of the development wells that we drill in any given year are contained within the Sproule defined proved undeveloped or probable undeveloped inventory. At our current pace of investment and drilling it will take approximately 10 years to develop all the currently identified probable undeveloped reserves.

Significant Factors or Uncertainties

We have a significant amount of proved non-producing and proved undeveloped reserves assigned to our Canadian heavy oil properties located in the Province of Saskatchewan and at our Seal, Ardmore and Cold Lake heavy oil properties located in the Province of Alberta. Our conventional light oil and gas properties in Stoddart, British Columbia, the Pembina and Ferrier areas of Alberta and Divide County, North Dakota, USA also contain a significant quantity of proved non-producing and proved undeveloped reserves. As well, we have a significant amount of probable non-producing and probable undeveloped reserves assigned to these same properties. At the current prices, these development activities are economic. However, should oil and natural gas prices fall materially, these activities may not be economic and we could defer their implementation. In addition, reserves can be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, and well performance that are beyond our control and which could impact our development decisions. See also "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below.

	FORECAST PRICES AND COSTS	
YEAR	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
	CANADA	
2009	100,278	101,448
2010	97,693	102,769
2011	62,646	64,417
2012	57,001	60,238
2013	18,900	53,147
Remaining	48,455	128,264
Total (Undiscounted)	384,973	510,282
	UNITED STATES	
2009	26,355	26,355
2010	23,824	39,706
2011	-	39,706
2012	6,157	18,929
2013	-	1,668
Remaining	-	-
Total (Undiscounted)	56,336	126,365
	TOTAL	
2009	126,633	127,803
2010	121,517	142,475
2011	62,646	104,123
2012	63,158	79,167
2013	18,900	54,815
Remaining	48,455	128,263
Total (Undiscounted)	441,309	636,647

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity financings. Our operating budget allocates between 50 to 60 percent of our expected cash flow operations to exploration and development activities.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of these properties uneconomic.

Other Oil and Gas Information

Oil and Natural Gas Properties

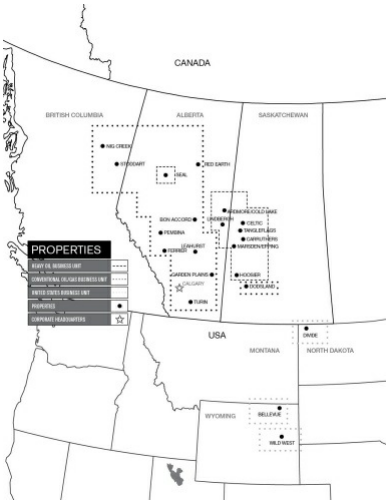
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2008, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Conventional Oil and Gas and U.S. business units. Each business unit has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these business units, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Baytex invested approximately $70 million in undeveloped land over the past two years targeting three light oil resource plays. These plays include the Bakken/Three Forks in the Williston Basin of North Dakota, the Viking in southwestern Saskatchewan and eastern Alberta and a Mowry Shale exploratory play in the Powder River Basin of eastern Wyoming. These light oil resources plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

The map below highlights the geographic location of our principal properties.

Baytex Energy Trust – Principal Properties



Heavy Oil Business Unit

The Heavy Oil business unit accounts for more than 55% of current production and more than 65% of oil-equivalent reserves. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 250 bbl/d of crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2008, production in the Heavy Oil business unit averaged approximately 23,530 bbl/d of heavy oil and 6,654 Mcf/d of natural gas (24,639 Boe/d). Baytex drilled 111 (103.8 net) wells in the Heavy Oil business unit resulting in 105 (97.8 net) oil wells, 4 (4.0 net) stratigraphic test wells, and 2 (2.0 net) dry and abandoned wells, for a success rate of 98%.

The Heavy Oil business unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore and Peace River in Alberta. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of our large inventory of heavy oil projects, we are able to select from a wide range of investment opportunities to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's historical area of emphasis around Lloydminster. Our net undeveloped lands in the Heavy Oil business unit totalled approximately 348,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Heavy Oil Business Unit:

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2008 was approximately 1,395 bbl/d of oil and 455 Mcf/d of natural gas (1,471 boe/d). Seven successful oil wells and no dry holes were drilled in the area during 2008. Baytex anticipates drilling four wells in this area in 2009. Due to extensive Baytex infrastructure in this area, operating expenses in 2008 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2008.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. No new wells were drilled in 2008, but 4 re-completions were conducted. Despite the absence of new well drilling, year-over-year production decline was only about 8% due mostly to strong performance of the ongoing waterflood. Average production in 2008 was approximately 2,115 bbl/d of heavy oil and 650 Mcf/d of natural gas (2,224 boe/d). Net undeveloped lands were 9,900 acres at year-end 2008.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 4,670 bbl/d of heavy oil and 1,118 Mcf/d of natural gas (4,856 boe/d) during 2008. (This production number includes very minor production in the area held prior to the Celtic acquisition). Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2009, Baytex expects to drill 10 new wells and re-complete approximately 45 existing wells. Net undeveloped lands were 8,800 acres at year-end 2008.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2008 was approximately 507 bbl/d. Baytex drilled two successful oil wells in the Cold Lake area in 2008, and we plan to drill three new wells in the area in 2009. Net undeveloped lands were 13,600 acres at year-end 2008.

Dodsland, Saskatchewan: During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 API) oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex targeted the less permeable but undeveloped areas of the play and drilled a 1,400 metre horizontal well in 2008. The horizontal well was completed with 7 fracture stimulations, applying the same multi-zone fracture technology that is used to stimulate horizontal wells in the Bakken oil play in southeast Saskatchewan and North Dakota. At year-end 2008, Baytex had leased 34,600 net acres in the play. Ultimately, up to 150 wells may be drilled on these lands.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2008 was approximately 3,380 bbl/d of oil and 831 Mcf/d of natural gas (3,518 boe/d). Twenty-three successful oil wells were drilled in this region in 2008. In addition, a significant facility expansion involving water flow-lining and conservation of the solution gas was completed. This project has reduced operating costs in the area and tied-in approximately 300 Mcf/d of solution gas into the local sales network. For 2009, a further 14 wells are planned. Net undeveloped lands were 26,300 acres at year-end 2008.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in 105 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced using horizontal wells at initial rates of 150 to 250 bbl/d per well, without employing more cost-intensive methods such as steam injection. In 2008, Baytex drilled four stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 19 horizontal production wells in 2008, bringing the total number of producing wells to 44. The average production rate during 2008 was 3,707 bbl/d of heavy oil. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase economic oil reserves beyond what is achievable with cold primary recovery. A cyclic steam pilot project was carried out on an existing horizontal producer during 2008 to validate the numerical reservoir simulation models. Due to the positive results from our steam pilot, the year-end 2008 reserve report included an assignment for thermal reserves at Seal for the first time. This reserve assignment supports our assessment that commercial cyclic steam development at Seal is economically viable. Seal area facilities were expanded in 2008 by constructing a water disposal plant and a fuel gas supply pipeline. Operating costs for primary production are forecasted to remain very low at $4 to $5/bbl and the gas pipeline ensures an adequate fuel supply for future thermal development of the property. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2009, Baytex plans to drill two additional stratigraphic test wells and 14 additional cold horizontal production wells. Net undeveloped lands were 65,000 acres at year-end 2008.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of re-completion opportunities. In 2008, Baytex drilled 3 wells and a further 15 wells were either re-started or re-completed to a new zone. Average production during 2008 was approximately 1,626 bbl/d of heavy oil and 915 Mcf/d of natural gas (1,779 boe/d). In 2009, Baytex plans to re-work or re-complete about 15 existing wells. Net undeveloped lands were 7,100 acres at year-end 2008.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.25% working interest. Company-interest production is approximately 800 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. Nine (1.9 net) wells were drilled in this area in 2008. Baytex expects the field operator to maintain a level of activity that would result in an approximately flat production rate. Net undeveloped lands were 11,000 acres at year-end 2008.

Conventional Oil and Gas Business Unit

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties. In addition to Baytex's historical light oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Conventional Oil and Gas Business Unit produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2008, production from this business unit averaged 48,066 Mcf/d of natural gas sales and 7,401 bbl/d of light oil and NGL (15,412 boe/d). During 2008, the Conventional Oil and Gas Business Unit drilled 31 (21.4 net) wells resulting in 18 (11.9 net) gas wells, 7 (4.1 net) oil wells, 2 (1.4 net) service wells, and 4 (4.0 net) dry holes for a success rate of 87.1% (81.3% net). Our net undeveloped lands in this business unit were approximately 329,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Conventional Oil and Gas Business Unit:

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2008, production for the area averaged approximately 2,524 Mcf/d of gas and 264 bbl/d of light oil (685 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2008, Baytex drilled two (1.75 net) oil wells in this area. At year-end 2008, Baytex had 11,500 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2008 averaged approximately 2,209 Mcf/d of gas (368 boe/d). At year-end 2008, Baytex had 18,100 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 4,109 Mcf/d of gas and 11 bbl/d of NGL (696 boe/d) during 2008 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2008, Baytex participated in the drilling of 4 operated and 1 non-operated locations, resulting in 4 (2.9 net) producing gas wells and 1 (1.0 net) dry hole. At year-end 2008, Baytex had 11,700 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its initial position in Pembina in June 2007 and further expanded its presence in the area through the acquisition of Burmis in June 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations including the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2008, Pembina production averaged 4,062 bbl/d of light oil and NGL and 13,272 Mcf/d of gas (6,274 boe/d). Baytex participated in drilling 6 (5.0 net) operated and 2 (0.6 net) non-operated locations in 2008. Four wells (2.3 net) were drilled to test Nisku prospects, resulting in 1 (0.6 net) oil well, 1 (0.4 net) gas well and 2 (1.4 net) service wells. Four (3.3 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2008, resulting in 3 (3.0 net) gas wells and 1 (0.25 net) dry hole. The 2009 drilling program for Pembina will include up to three wells to evaluate Nisku prospects and four wells for multi-zone Cretaceous potential. During the first quarter of 2009, Baytex will be constructing a pipeline in the Pembina O'Chiese area to increase gas volumes delivered to market and improve netback prices for our Pembina production. At year-end 2008, Baytex had 32,600 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001, and significantly increased its presence with a 2004 acquisition of a private company. During 2008, production averaged approximately 5,971 Mcf/d of sales gas and 11 bbl/d of NGL (1,006 boe/d). This area has year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas produced from this area is processed at two Baytex-operated gas plants. During 2008, Baytex drilled 5 (1.7 net) wells in this area, resulting in 3 (1.5 net) gas wells and 2 (0.2 net) oil wells. At year-end 2008, Baytex had 29,200 net undeveloped acres in this area.

Red Earth/Goodfish/Lafond, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2008 averaged approximately 4,058 Mcf/d of gas and 770 bbl/d of light oil and NGL (1,446 boe/d). During 2008, Baytex drilled 4 (3.1 net) wells in this area, resulting in 1 (0.5 net) oil well, 1 (0.6 net) gas well, and 2 (2.0 net) dry holes. At year-end 2008, Baytex had 28,600 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2008 averaged approximately 8,375 Mcf/d of gas and 1,392 bbl/d of oil and NGL (2,788 boe/d). Baytex drilled 3 (2.4 net) wells in 2008 resulting in 1 (1.0 net) oil well, 1 (0.4 net) gas well, and 1 (1.0 net) dry hole. During 2009, Baytex plans to drill two wells in the area. At year-end 2008, Baytex had 32,000 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2008 averaged approximately 519 bbl/d of oil and NGL and 1,383 Mcf/d of gas (750 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2008, Baytex drilled one (0.1 net) gas well in this area. At year-end 2008, Baytex had 9,600 net undeveloped acres in this area.

United States Business Unit

Through our wholly-owned subsidiary, Baytex USA, we acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. During 2008, Baytex USA drilled and/or acquired an interest in 34 (12 net) wells and increased its acreage position to over 120,000 net acres. Net production from the United States properties averaged 188 boe/d in 2008 and 339 boe/d in December 2008.

Listed below is a brief description of the principal properties within the United States Business Unit:

Williston Basin – Bakken/Three Forks Project: This light oil resource play is located in the Divide and Burke Counties of North Dakota. Production is primarily from horizontal wells using multi-zone hydraulic fracturing in the Bakken and Three Forks formations. Both zones are accessed through a single horizontal lateral. Baytex USA has invested in approximately 251,000 (94,000 net) acres of land. In 2008, Baytex USA participated in 8 gross (3 net) wells. Baytex USA also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. This survey was 73% complete at the end of 2008. Net production from the project was approximately 341 boe/d in the fourth quarter of 2008. In 2009, Baytex USA plans to drill 6 gross (2.25 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial rates expected to be 190 boe/d or more per well and average recoveries expected to be 280 mboe/well or more.

Powder River Basin – Mowry Shale Play (Wild West): In September 2007, Baytex USA acquired its initial leasehold interest in this Mowry shale play in Wyoming covering approximately 15,300 (9,200 net) acres. A vertical well (Baytex USA 60% working interest) was drilled in 2008 to acquire core and ultimately serve as a microseismic monitoring well for subsequent horizontal-well fracturing. Completion of the vertical well, including hydraulic fracturing, is scheduled for the first quarter of 2009. Baytex USA views horizontal, multi-zone hydraulically-fractured wells as the most promising method to ultimately develop the Mowry, although there have been no horizontal wells drilled in the project area to-date. A horizontal well is planned to further evaluate the prospect in 2009. Ultimately, the project may include up to 60 horizontal wells.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2008.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Gas (Mcf/d)	Oil Equivalent (boe/d)
Heavy Oil Business Unit				
Ardmore	-	1,395	455	1,471
Carruthers	-	2,115	651	2,224
Celtic	-	4,670	1,118	4,856
Cold Lake	-	507	-	507
Golden lake	-	726	-	726
Greenstreet	-	-	1,238	206
Hoosier	-	452		452
Lashburn	-	65	34	71
Lindbergh	-	797	59	807
Maidstone	-	883	-	883
Marsden	-	729	-	729
Neilburg	-	548	-	548
Poundmaker	-	1,560	317	1,613
Seal	-	3,707	-	3,707
Silverdale / Epping / Macklin / Buzzard	-	2,651	445	2,725
Sugden	-	546	-	546
Tangleflags	-	1,626	915	1,779
Remaining properties	-	553	1,422	789
Total Heavy Oil Business Unit	-	23,530	6,654	24,639
Conventional Oil and Gas Business Unit				
Bon Accord	264	-	2,524	685
Darwin/Nina	-	-	2,209	368
Goodfish	-	-	3,590	598
Hamburg/Chinchaga	33	-	1,957	359
Leahurst	11	-	4,109	696
Pembina	4,062	-	13,272	6,274
Red Earth	770	-	56	779
Richdale / Sedalia	11	-	5,971	1,006
Stoddart	1,392	-	8,375	2,788
Tangent	-	-	281	47
Turin	519	-	1,383	750
Viking	-	-	1,079	180
Remaining Properties	339	-	3,260	882
Total Conventional Oil and Gas Business Unit	7,401	-	48,066	15,412
United States Business Unit	181	-	41	188
Grand Total	7,582	23,530	54,761	40,239

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2008:

($000s)	Canada	United States	Total
Property acquisition costs [1]			
Proved properties	131,584	5,636	137,220
Unproved properties	63,587	64,292	127,879
Total Property acquisition costs	195,171	69,928	265,099
Development Costs [2]	140,887	36,892	177,779
Exploration Costs [3]	6,026	1,278	7,304
Total	342,084	108,098	450,182

Notes:
(1) Property acquisition costs include the corporate acquisition of Burmis and are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of geological and geophysical capital expenditures and drilling costs for 2008 exploratory wells drilled.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	774	452.8	827	415.5	601	432.7	357	271.2
British Columbia	56	55.2	28	26.8	34	29.6	16	13.2
Saskatchewan	1,083	1,006.9	797	755.4	46	42.3	54	51.3
North Dakota	27	8.4	2	0.7	-	-	-	-
Wyoming	2	1.3	3	2.1	-	-	-	-
Total	1,942	1,524.6	1,657	1,200.5	681	504.6	427	335.7

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2008.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	594,047	446,722
British Columbia	85,583	61,928
Saskatchewan	184,870	168,428
Total Canada	864,500	677,078
United States		
North Dakota	251,590	94,346
Utah	920	460
Wyoming	47,435	25,248
Total United States	299,945	120,054
Grand Total	1,164,445	797,132

We expect that rights to explore, develop and exploit approximately 119,383 net acres of our undeveloped land holdings may expire on or before December 31, 2009. There are no material drilling commitments associated with the land holdings expiring by December 31, 2009.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2008.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	1	0.3	121	106.4
Natural Gas	3	2.9	14	9.4
Evaluation	6	4.4	-	-
Service	-	-	-	-
Dry	3	2.9	4	4.0
Total	13	10.5	139	119.8

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2008, see Notes 16 and 17 to our annual audited financial statements as at and for the year ended December 31, 2008, which are incorporated herein by reference.

Tax Horizon

We are a taxable entity under the Tax Act and are taxable only on income that is not distributed or distributable to our Unitholders. We distribute all of our taxable income to our Unitholders and meet the requirements of the Tax Act applicable to us. As a result of our tax efficient structure, annual taxable income is currently transferred from our operating entities to the Trust and from the Trust to Unitholders. This is primarily accomplished through the deduction by Baytex of the NPI on underlying oil and gas properties and the deduction of interest on the Notes.

Commencing in January 2011 (provided that we experience only "normal growth" and no "undue expansion" before then), we may be liable for tax at the federal "net corporate income tax rate" combined with the "provincial SIFT tax rate" (effectively, the federal general corporate tax rate plus the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment) on all income payable to Unitholders, which we will not be able to deduct in computing our taxable income, as a result of being characterized as a SIFT trust. The effect of this new legislation is reflected in the after tax net revenue amounts disclosed in this Annual Information Form, other than the recently announced provincial SIFT tax rate.

For more information, see "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations* ", "*Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations*" and "*Risk Factors – Risks Associated with Government Regulation – Our status as a mutual fund trust may be changed or affected by changes in legislation* ".

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines which are expected to be incurred by us for the periods indicated.

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($ millions)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($ millions)
Total liability as at December 31, 2008	267.74	32.21
Anticipated to be paid in 2008 ;	1.22	1.17
Anticipated to be paid in 2009 ; &# 160; ;	1.11	0.99
Anticipated to be paid in 2010	0.71	0.59

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by us upon abandonment. Expenditures related to environmental obligations are expected to be funded out of cash flow.

We estimate the costs to abandon and reclaim all of our producing and shut in wells, facilities, and pipelines. In the table above, no estimate of salvage value is netted against the estimated cost. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The number of net wells for which we estimated we will incur reclamation and abandonment costs is 4,092 wells. This estimate includes all producing wells, all non producing wells, all standing cased wells and all suspended wells. The number of net wells for which Sproule estimated we will incur reclamation and abandonment costs is 660 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2008. Abandonment and reclamation costs have been estimated over a 50 year period. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of its associated producing area. Only well abandonment costs, net of downhole salvage value were deducted by Sproule in estimating future net revenue in the Sproule Report. The additional liability associated with our existing wells, pipelines and facility reclamation costs, net of salvage, which was estimated to be $267.7 million ($32.2 million discounted at 10 percent), was not deducted in estimating future net revenue.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2008.

	($000s)
Exploration and Development	
Land	9,534
Seismic	4,947
Drilling and completion	132,296
Equipment	34,720
Other	3,586
Total exploration and development	185,083
Acquisitions (net of dispositions)	
Corporate acquisitions	180,467
Property acquisitions	84,826
Property dispositions	(194)
Total Acquisitions (net of dispositions)	265,099
Net capital expenditures	450,182

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2009, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Description of Our Business and Operations – Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data and Oil and Natural Gas Information* ".

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boe/d)
CANADA					
Total Proved	5,511.3	28,057.1	56,659.6	1,902.1	44,913.7
Total Proved plus Probable	6,066.6	29,577.2	62,021.4	2,087.3	48,068.0
UNITED STATES					
60;					
Total Proved	560.4	-	483.0	-	640.9
Total Proved plus Probable	562.4	-	483.0	-	642.9
TOTAL					
0;					
Total Proved	6,071.7	28,057.1	57,142.6	1,902.1	45,554.6
60; Total Proved plus Probable	6,629.0	29,577.2	62,504.4	2,087.3	48,710.9

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

Production History

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

	Quarter Ended 2008				Year Ended
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31, 2008
Average Daily Production [1]					
Light Oil and NGL (bbl/d) [2]	7,803	8,377	6,778	7,330	7,575
Heavy Oil (bbl/d)	24,635	24,078	22,905	22,484	23,530
Natural Gas (MMcf/d)	57,583	60,500	50,974	50,058	54,802
Total (boe/d)	42,035	42,538	38,179	38,157	40,239
Average Net Production Prices Received					
Light Oil and NGL($/bbl) [2]	55.31	107.41	109.26	84.91	88.92
Heavy Oil ($/bbl)	38.93	84.65	78.92	59.65	65.22
Natural Gas ($/Mcf)	7.05	8.01	9.29	7.42	7.92
Total ($/boe)	42.71	80.44	79.15	61.16	65.66
Royalties Paid					
Light Oil and NGL($/bbl) [2]	15.66	26.25	28.05	22.48	22.97
Heavy Oil ($/bbl)	6.09	19.50	15.38	11.14	12.93
Natural Gas ($/Mcf)	1.18	1.63	1.84	1.37	1.50
Total ($/boe)	8.08	18.52	16.65	12.64	13.92
Production Costs [3][4]					
Light Oil and NGL($/bbl) [2]	13.64	11.41	13.86	10.81	12.38
Heavy Oil ($/bbl)	11.59	12.63	11.24	10.69	11.55
Natural Gas ($/Mcf)	2.04	1.76	1.90	1.68	1.85
Total ($/boe)	12.12	11.92	11.76	10.60	11.60
Transportation					
Light Oil and NGL($/bbl) [2]	0.13	0.61	0.61	0.56	0.47
Heavy Oil ($/bbl)	5.24	4.16	3.98	2.94	4.22
Natural Gas ($/Mcf)	0.13	0.13	0.12	0.14	0.13
Total ($/boe)	3.28	2.65	2.67	2.05	2.74
Netback Received [5]					
Light Oil and NGL($/bbl) [2]	25.88	69.14	66.74	51.06	53.10
Heavy Oil ($/bbl)	16.01	48.36	48.32	34.88	36.52
Natural Gas ($/Mcf)	3.70	4.49	5.43	4.23	4.44
Total ($/boe)	19.23	47.35	48.07	35.87	37.40

Notes:
(1) Before deduction of royalties.
(2) Our NGL volumes are not material, and have been grouped with light oil for reporting purposes.
(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.
(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalties, operating costs, transportation and losses/gains on commodity and foreign exchange contracts from revenues.

Marketing Arrangements

Natural Gas

We continue to maintain a risk-mitigating strategy and cultivate a diverse natural gas sales portfolio, which encompasses a variety of pricing mechanisms and term commitments. Our marketing objectives also include protecting or securing minimum prices for up to 50% of net production for terms not exceeding two years. Our hedging methodology generally includes employing collars, floors or fixed price contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. Our natural gas portfolio includes sales to industrial consumers, distribution companies and traditional aggregators.

For 2009, Baytex has entered into two costless collar contracts which will provide downside protection on the natural gas price while still allowing Baytex to participate in upside price potential. For calendar 2009, a costless collar has been put in place on 4.7 MMcf/d of natural gas, with a floor price of $7.39/Mcf and a ceiling price of $8.39/Mcf. For April to December 2009, a costless collar has been put in place on 4.7 MMcf/d of natural gas, with a floor price of $5.28/Mcf and a ceiling price of $6.65/Mcf.

Oil and NGL

Benchmark WTI prices began 2008 around US$92 per barrel, climbed to an all-time high of US$145 per barrel in July, and ended the year at about US$40 per barrel. The average WTI price for 2008 was US$99.64 per barrel, an increase of 38 percent from the 2007 average of US$72.31 per barrel.

Baytex's light oil and natural gas liquids prices averaged $88.92 per barrel in 2008, an increase of 36 percent from the 2007 average of $65.53 per barrel. Our heavy oil prices averaged $72.20 per barrel in 2008, an increase of 63% from the 2007 average of $44.28 per barrel.

For 2009, Baytex has entered into two costless collar contracts which will provide significant downside protection on the oil price while still allowing Baytex to participate in upside price potential. WTI costless collars have been put in place for 2009 on 4,000 bbl/d, at a weighted average price from US$100.00 to US$154.55 per barrel. In addition, Baytex has entered into a series of physical heavy sour crude oil sales agreements requiring delivery of blended volumes for sales at a fixed pricing differential to WTI. For 2009, we have two contracts in place to sell 10,340 bbl/d at approximately 67% of WTI. To further mitigate our price exposure, we recently entered into two more physical heavy sour crude oil sales agreements, each for 775 bbl/d for the period from April 2009 to August 2009. The first agreement is priced at WTI minus a fixed US$10.00 per barrel and the second one is priced at 80% of WTI.

Environmental Policies

We have an active program to monitor and comply with all environmental laws, rules and regulations applicable to our operations. Our policies require that all employees and contractors report all breaches or potential breaches of environmental laws, rules and regulations to our senior management and all applicable governmental authorities. Any material breaches of environmental law, rules and regulations must be reported to the Board of Directors.

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY TRUST

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal fractional undivided beneficial interest in any distribution from us (whether of net income, net realized capital gains or other amounts) and in any of our net assets in the event of our termination or winding-up. All Trust Units outstanding from time to time are entitled to an equal share of any distributions by us and, in the event of termination or winding-up of the Trust, in any of our net assets. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require us to redeem any or all of the Trust Units held by such holder. See " – *Trust Indenture – Redemption Right*".

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in us or Baytex. Corporate law does not govern us and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

A return on an investment in us is not comparable to the return on an investment in a fixed income security. The recovery of an initial investment in us is at risk, and the anticipated return on such investment is based on many performance assumptions. Although we intend to make cash distributions to holders of Trust Units, these cash distributions may be reduced or suspended. The actual amount distributed will depend on numerous factors including: the financial performance of Baytex, debt obligations, working capital requirements and future capital requirements. In addition, the market value of the Trust Units may decline if our cash distributions decline in the future and that market value decline may be material.

It is important for an investor to consider the particular risk factors that may affect the industry in which it is investing, and therefore the stability of the distributions that it receives. See " *Risk Factors*".

The after tax return from an investment in Trust Units to Unitholders subject to Canadian income tax can be made up of both a return on capital and a return of capital. That composition may change over time, thus affecting an investor's after tax return. Returns on capital are generally taxed as ordinary income in the hands of a Unitholder. Returns of capital are generally tax deferred (and reduce the Unitholder's cost base in the Trust Unit for tax purposes).

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

Special Voting Units

In order to allow us flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation of Special Voting Units which enable us to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by Baytex or our other subsidiaries in connection with other exchangeable share transactions. For a description of the Exchangeable Shares, see "*Baytex Share Capital – Exchangeable Shares*".

An unlimited number of Special Voting Units may be created and issued pursuant to the Trust Indenture. Holders of Special Voting Units are not entitled to any distributions of any nature whatsoever from us and are entitled to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors. Except for the right to vote at meetings of Unitholders, the Special Voting Units do not confer upon the holders thereof any other rights.

Convertible Debentures

On June 6, 2005, we issued $100 million principal amount of Convertible Debentures for net proceeds of $95.8 million. The Convertible Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid Trust Units at a conversion price of $14.75 per Trust Unit. The Convertible Debentures mature on December 31, 2010 at which time they are due and payable. The Convertible Debentures are redeemable after December 31, 2008 at our option at a price of $1,050 per Convertible Debenture after December 31, 2008 and on or before December 31, 2009 and at a price of $1,025 per Debenture after December 31, 2009 and before maturity, in each case, plus accrued and unpaid interest thereon, if any. For a complete description of the Convertible Debentures, reference should be made to the indenture creating the Convertible Debentures, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 9, 2005).

Trust Indenture

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including our termination and the sale or transfer of our property as an entirety or substantially as an entirety requires approval by special resolution of the Unitholders. Any approval or consent of Unitholders in relation to any matter required by any regulatory body will require a majority of, or such other level of approval of Unitholders as may be stipulated by such regulatory authority, including as to the exclusion of interested or other Unitholders in the calculation of such level of approval.

The following is a summary of certain provisions of the Trust Indenture. For a complete description of the Trust Indenture, reference should be made to the Trust Indenture, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 5, 2008).

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, will incur or be subject to any liability in contract or in tort in connection with us or our obligations or affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, our assets. Pursuant to the Trust Indenture, we have agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a Unitholder from or arising as a result of such Unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of us must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from our liabilities to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against us (to the extent that claims are not satisfied by us) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely in view of the fact that our primary activity is to hold securities, and the majority of our business operations are currently carried on by Baytex.

Our activities and those of Baytex are conducted in such a way and in such jurisdictions so as to avoid as much as possible any material risk of liability to Unitholders for claims against us. These activities include obtaining appropriate insurance, where available, for the operations of Baytex and having contracts signed by or on behalf of us that include a provision that such obligations are not binding upon Unitholders personally.

In addition, on July 1, 2004 the *Income Trusts Liability Act* (Alberta) came into force, creating a statutory limitation on the liability of unitholders of Alberta income trusts such as us. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after July 1, 2004.

Issuance of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that Baytex may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as Baytex may determine.

Cash Distributions

We make cash distributions on the 15th day of each month (or the first business day thereafter) to holders of Trust Units of record on the immediately preceding record date.

The Board of Directors on our behalf reviews our distribution policy from time to time. The actual amount distributed is dependent on the commodity price environment and is at the discretion of the Board of Directors. Our current distribution practice targets the use of between 50 to 60 percent of our available cash flow from operations for capital expenditures. Depending upon commodity prices, between 50 to 60 percent of our available cash flow from operations could fund up to all of our capital expenditures, including both exploration and development expenditures and minor property acquisitions, but excluding major acquisitions.

Pursuant to various agreements with Baytex's lenders, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under Baytex's facilities or upon a material borrowing base shortfall or default.

Baytex's senior subordinated notes also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution to us and the payment of interest or principal on subordinated debt owed to us. Baytex is restricted from making any restricted payments, including distributions to us, if a default or event of default under the note indenture governing the subordinated debt has occurred and is continuing. If no such default or event of default has occurred and is continuing, Baytex may make a distribution to us provided at the time either (A) (i) its ratio of consolidated debt to consolidated cash flow from operations does not exceed 3 to 1, (ii) its fixed charge coverage ratio for the preceding four fiscal quarters is greater than 2.5 to 1 and (iii) the aggregate of all restricted payments declared or made after July 9, 2003 does not exceed the sum of 80 percent of the consolidated cash flow from operations accrued on a cumulative basis since July 9, 2003 plus the net cash proceeds received by Baytex from the issuance of deeply subordinated intercompany debt or the receipt of capital contributions from the Trust plus net proceeds received by Baytex from the issuance of and upon conversion of debt and other securities or (B) the aggregate amount of all restricted payments declared or made after July 9, 2003 does not exceed the sum of permitted restricted payments not previously made plus US$30,000,000.

Cash distributions on the Trust Units are paid at the discretion of the Board of Directors and can fluctuate depending on the level of cash flow from operations. The following table summarizes the cash distributions per Trust Unit paid by us since September, 2003. Our historical cash distributions may not be reflective of future cash distributions, which will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time. See "*Risk Factors*".

Month [1]	2009	2008	2007	2006	2005	2004	2003
January	$0.18	$0.18	$0.18	$0.18	$0.15	$0.15	-
February	0.12	0.18	0.18	0.18	0.15	0.15	-
March		0.20	0.18	0.18	0.15	0.15	-
April		0.20	0.18	0.18	0.15	0.15	-
May		0.20	0.18	0.18	0.15	0.15	-
June		0.25	0.18	0.18	0.15	0.15	-
July		0.25	0.18	0.18	0.15	0.15	-
August		0.25	0.18	0.18	0.15	0.15	-
September		0.25	0.18	0.18	0.15	0.15	$0.15
October		0.25	0.18	0.18	0.15	0.15	0.15
November		0.25	0.18	0.18	0.15	0.15	0.15
December		0.18	0.18	0.18	0.15	0.15	0.15
Total		$2.64	$2.16	$2.16	$1.80	$1.80	$0.60

Note:

(1) Cash distributions are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month.

Distributions and Allocations of Trust Income

The Trust Indenture provides that distributable cash of the Trust shall be calculated for each period between distribution record dates, which are currently calendar months, provided that December 31 shall be always be a distribution record date. The Trustee may, upon the recommendation of Baytex, declare payable and distribute all or part of the distributable cash to the Unitholders of record on the last day of each such calendar month. The Trust Indenture further provides that all net income, net realizable taxable gains and other income shall be distributed such that the Trust has no tax liability in any year. This income is allocated to Unitholders for tax purposes. In addition, the Trust Indenture provides that such income may be paid in whole or in part by cash or in Trust Units. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of the Board of Directors to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all unitholders.

The distribution by the Trust of such income is enforceable by Unitholders on the payment date determined by the Trustee.

For more information, see "*Risk Factors – Risks Associated with our Structure as a Trust – We allocate all of our income* ".

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to us of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by us, the holder thereof will only be entitled to receive a price per Trust Unit equal to the lesser of: (i) 90 percent of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to us for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "market price" is an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price will be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price will be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price will be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate amount payable by us in respect of any Trust Units surrendered for redemption during any calendar month will be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by us in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year will not exceed $100,000; provided that we may, in our sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the price payable by us in respect of Trust Units tendered for redemption in such calendar month will be paid on the last day of the following month as follows: (i) firstly, by distributing Notes having an aggregate principal amount equal to the aggregate price of the Trust Units tendered for redemption; and (ii) secondly, to the extent that we do not hold Notes having a sufficient principal amount outstanding to effect such payment, by us issuing promissory notes to Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes ("**Redemption Notes**") will have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Unitholder, the outstanding Trust Units are not listed for trading on the Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market which provides, in the sole discretion of Baytex, representative fair market value price for the Trust Units or trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption, then such Unitholder will be entitled to receive a price per Trust Unit equal to 90 percent of the fair market value thereof as determined by Baytex as at the date on which such Trust Units were tendered for redemption. The aggregate price payable by us in such circumstances in respect of Trust Units tendered for redemption in any calendar month will be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes which may be distributed *in specie* to Unitholders in connection with redemption will not be listed on any stock exchange and no market is expected to develop in such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by RRSPs, RESPs, DPSPs, RDSPs, TFSAs and RRIFs.

Non-resident Unitholders

It is intended that we comply with the requirements under the Tax Act for mutual fund trusts at all relevant times such that we maintain our status as a mutual fund trust for purposes of the Tax Act. If at any time we, or Baytex, become aware that our ability to continue to qualify as a mutual fund trust is in jeopardy, Baytex on our behalf, shall monitor the holdings of Trust Units by "non-residents" of Canada (within the meaning of the Tax Act) and shall take such steps as are necessary or desirable to ensure that we are not maintained primarily for the benefit of non-residents or that we are otherwise able to continue to qualify as a mutual fund trust for purposes of the Tax Act, including the imposition of restrictions on the issuance or transfer of Trust Units to such non-residents, the sale of Trust Units held by such non-residents and de-listing the Trust Units from any non-Canadian stock exchange. The Trust Indenture also provides that none of us, the Trustee, or Baytex shall have any liability to non-residents as a result of the sale of their Trust Units in order for us to maintain compliance with the requirements under the Tax Act for mutual fund trusts. As at December 31, 2008, approximately 36 percent of our Trust Units were held by non-residents.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of our auditors, the approval of amendments to the Trust Indenture (except as described under the subheading "*Amendments to the Trust Indenture* " below), the sale of our property as an entirety or substantially as an entirety, and the commencement of winding-up our affairs. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of Baytex and the appointment of our auditors. In certain circumstances, such as the election of directors of Baytex, the Trustee is required to seek direction from the Unitholders as to the manner in which it is to vote the shares of Baytex held by us. See " *– Exercise of Voting Rights Attached to Shares of Baytex* ".

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20 percent of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least five percent of the votes attaching to all outstanding Trust Units will constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Units who are present at the meeting will be regarded as representing outstanding Trust Units equivalent in number to the votes attaching to such Special Voting Units.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Reporting to Unitholders

Our financial statements are audited annually by an independent recognized firm of chartered accountants. Our audited financial statements, together with the report of such chartered accountants, are mailed or otherwise delivered to Unitholders in accordance with applicable securities legislation and our unaudited interim financial statements are mailed or otherwise delivered to Unitholders in accordance with applicable securities legislation within the periods prescribed by such legislation. Our year end is December 31.

We are subject to the continuous disclosure obligations under all applicable securities legislation.

Take-over Bids

The Trust Indenture contains provisions to the effect that if a take-over bid is made for the Trust Units and not less than 90 percent of the Trust Units (other than Trust Units held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the take-over bid on the terms offered by the offeror.

The Trustee

Valiant Trust Company has been our trustee since our inception in 2003. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee will exercise its powers and carry out its functions thereunder as trustee honestly, in good faith and in our best interests and the interests of Unitholders and, in connection therewith, will exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee is generally appointed for a three-year term by the Unitholders. At the end of such term, the Unitholders will either re-appoint the Trustee or appoint a successor trustee for an additional three-year term. The Trustee may be removed by a special resolution of Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The Board of Directors has generally been delegated by the Trustee the significant management decisions relating to us. In particular, the Trustee has delegated to Baytex responsibility for any and all matters relating to the following: (i) an offering; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of, our material contracts; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the maximization of Unitholder value in the context of a response to an offer for Trust Units or for all or substantially all of the property and assets of us or Baytex; (vii) all matters relating to the redemption of Trust Units; (viii) all matters relating to the voting rights on any investments in our assets or any subsequent investments; (ix) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents are not liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to us or our property, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, an administration agreement in place between us and Baytex, and relying on Baytex thereunder, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, our property incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any appropriately qualified person, any reliance on any such evaluation, any action or failure to act of Baytex, or any other person to whom the Trustee has, with the consent of Baytex, delegated any of its duties thereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by Baytex to perform its duties under or delegated to it under the Trust Indenture or any other contract), including anything done or permitted to be done pursuant to, or any error or omission relating to, the rights, powers, responsibilities and duties conferred upon, granted, allocated and delegated to Baytex thereunder or under the administration agreement, or the act of agreeing to the conferring upon, granting, allocating and delegating any such rights, powers, responsibilities and duties to Baytex in accordance with the terms of the Trust Indenture or under the administration agreement, unless and to the extent such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees, shareholders, or agents.

If the Trustee has retained an appropriate expert or advisor or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, advisor or legal counsel, and notwithstanding any other provision of the Trust Indenture, the Trustee will not be liable for and will be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, advisor or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and will be conclusively deemed to be acting as Trustee of our assets and will not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to us or our property. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by a special resolution of Unitholders.

The Trustee may, without the approval of any of Unitholders, amend the Trust Indenture for the purpose of:

(a) ensuring our continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;

(b) ensuring that we will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act, as amended or replaced from time to time;

(c) ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;

(d) removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of us or any offering document pursuant to which our securities are issued with respect us, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of Unitholders are not prejudiced thereby; and

(e) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of Unitholders are not prejudiced thereby.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20 percent of the outstanding Trust Units; (b) a quorum of 50 percent of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by special resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of Unitholders, the Trustee will commence to wind-up our affairs on December 31, 2099. In the event that we are wound-up, the Trustee will sell and convert into money our property in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate our property, and will in all respects act in accordance with the directions, if any, of Unitholders in respect of termination authorized pursuant to the special resolution authorizing our termination. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all our known liabilities and obligations and providing for indemnity against any other outstanding liabilities and obligations, the Trustee will distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of our property among Unitholders in accordance with their pro rata holdings.

Exercise of Voting Rights Attached to Shares of Baytex

The Trust Indenture prohibits the Trustee from voting the shares of Baytex with respect to: (i) the election of directors of Baytex; (ii) the appointment of auditors of Baytex; or (iii) the approval of Baytex's financial statements, except in accordance with an ordinary resolution adopted at an annual meeting of Unitholders. The Trustee is also prohibited from voting the shares to authorize:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of Baytex, except in conjunction with an internal reorganization of the direct or indirect assets of Baytex as a result of which either Baytex or the Trust has the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any statutory amalgamation of Baytex with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) any statutory arrangement involving Baytex except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of Baytex to increase or decrease the minimum or maximum number of directors; or

(e) any material amendment to the articles of Baytex to change the authorized share capital other than the creation of additional classes of Exchangeable Shares or to amend the rights, privileges, restrictions and conditions attaching to any class of Baytex's shares in a manner which may be prejudicial to us, without the approval of Unitholders by special resolution at a meeting of Unitholders called for that purpose.

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY LTD.

Management of the Trust

The following table sets forth the name, municipality of residence, age as at December 31, 2008, position held with Baytex and principal occupation of each of the directors and officers of Baytex.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
John A. Brussa [2] [3] [4] [6] Calgary, Alberta	51	Director	Partner with Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	53	Director and Executive Chairman	Executive Chairman of Baytex
Edward Chwyl [2] [3] [4] Victoria, B.C.	65	Director	Independent Businessman
Naveen Dargan [1] [2] [4] Calgary, Alberta	51	Director	Independent Businessman
R.E.T. (Rusty) Goepel [1] Vancouver, B.C.	66	Director	Senior Vice President of Raymond James Ltd.
Anthony W. Marino Calgary, Alberta	48	Director, President and Chief Executive Officer	President and Chief Executive Officer of Baytex
Gregory K. Melchin [1] Calgary, Alberta	55	Director	Independent Businessman
Dale O. Shwed [3] [7] Calgary, Alberta	50	Director	President and Chief Executive Officer of Crew Energy Inc.
W. Derek Aylesworth Calgary, Alberta	46	Chief Financial Officer	Chief Financial Officer of Baytex
Randal J. Best Calgary, Alberta	52	Senior Vice President, Corporate Development	Senior Vice President, Corporate Development of Baytex
Stephen Brownridge Calgary, Alberta	49	Vice President, Heavy Oil	Vice President, Heavy Oil of Baytex
Brett J. McDonald Calgary, Alberta	46	Vice President, Land	Vice President, Land of Baytex
Timothy R. Morris Denver, Colorado	52	Vice President, US Business Development	Vice President, US Business Development of Baytex
R. Shaun Paterson Calgary, Alberta	55	Vice President, Marketing	Vice President, Marketing of Baytex
Marty L. Proctor Calgary, Alberta	48	Chief Operating Officer	Chief Operating Officer of Baytex
Mark F. Smith Calgary, Alberta	51	Vice President, Conventional Oil & Gas	Vice President, Conventional Oil & Gas of Baytex
Shannon M. Gangl Calgary, Alberta	46	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP

Notes:

(1) Member of our Audit Committee.
(2) Member of our Compensation Committee.
(3) Member of our Reserves Committee.
(4) Member of our Nominating and Governance Committee.
(5) Baytex's directors hold office until the next annual general meeting of Unitholders or until each director's successor is appointed or elected pursuant to the *Business Corporations Act* (Alberta).
(6) Mr. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (which became Rider Resources Ltd.). The plan of arrangement was completed in April 2002.
(7) Mr. Shwed was a director of Echelon Energy Inc., a private company incorporated under the *Business Corporations Act* (Alberta). In September 1999, a receiver-manager was appointed over the assets of Echelon.

Listed below is a biographical description for each of our directors and officers, including their principal occupations during the five preceding years.

John A. Brussa became a Director of Baytex on October 8, 1997. He is a partner at Burnet, Duckworth & Palmer LLP and focuses on tax law. He was admitted to the Alberta bar in 1982. Mr. Brussa is a director of several public companies including Crew Energy Inc., Energy Savings Income Fund, Highpine Oil & Gas Limited, Harvest Energy Trust, Progress Energy Resources Corp., Penn West Energy Trust and Storm Exploration Inc. He holds a Bachelor of Laws degree from the University of Windsor where he was a gold medalist and a Bachelor of Arts, History and Economics degree also from the University of Windsor.

Raymond T. Chan was appointed Executive Chairman of Baytex on January 1, 2009. He originally joined Baytex in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President and Chief Executive Officer (September 2003 to November 2007); and Chief Executive Officer (November 2007 to December 2008). Mr. Chan has been a director of Baytex since October 1998. Mr. Chan has helc senior executive positions in the Canadian oil and gas industry since 1982, including chief financial officer titles at Tarragon Oil and Gas Limited, American Eagle Petroleums Ltd. and Gane Energy Corporation. Mr. Chan holds a Bachelor of Commerce degree and is a chartered accountant.

Edward Chwyl became a Director of Baytex on May 27, 2003 and was Chairman of the Board of Directors from September 2003 to December 2008. He was appointed Lead Independent Director of Baytex on February 17, 2009. He holds a Bachelor of Science degree in Chemical Engineering and a Master of Science degree in Petroleum Engineering. He is a retired businessman with over 35 years experience in the oil and gas industry in North America, most notably as President and Chief Executive Officer of Tarragon Oil and Gas Limited from 1989 to 1998. Prior thereto, he held various technical and executive positions within the oil and gas industry in Canada and the United States.

Naveen Dargan became a Director of Baytex on September 1, 2003. He has been an independent businessman since June 2003. Prior to this, he held the position of Senior Managing Director and Head of Energy Investment Banking and Raymond James Ltd., an investment banking firm and its predecessor companies. Mr Dargan is a director of Trinidad Drilling Ltd. and CCS Corporation. He holds a Bachelor of Arts (Honours) degree in Mathematics and Economics, a Master of Business Administration degree and a Chartered Business Valuator designation.

R.E.T. (Rusty) Goepel became a Director of Baytex on May 11, 2005. He is currently Senior Vice President for Raymond James Ltd. He commenced his career in investment banking in 1968 and was President and co-founder of Goepel Shields & Partners, which later became Goepel McDermid Ltd. and was acquired by Raymond James Ltd. in 2001. Mr. Goepel holds a Bachelor of Commerce (Honours) degree.

Anthony W. Marino was appointed President, Chief Executive Officer and director of Baytex on January 1, 2009. Mr. Marino joined Baytex in November 2004 as Chief Operating Officer and was promoted to President and Chief Operating Officer in November 2007. Prior to joining Baytex, Mr. Marino was President and Chief Executive Officer of Dominion Exploration Canada Ltd. (a subsidiary of Dominion Resources Inc.). Mr. Marino's earlier experience includes managing the Jonah/Pinedale asset area for AEC Oil and Gas (USA) Inc., operations and business development management for Santa Fe Snyder Corp. and several technical and management positions with Atlantic Richfield Company. He is a registered professional engineer and a Chartered Financial Analyst, and has over 25 years of experience in the North American oil and gas industry. Mr. Marino has a Bachelor of Science degree with Highest Distinction in Petroleum Engineering from the University of Kansas and a Masters of Business Administration degree from California State University at Bakersfield. He is currently a member of the Board of Governors for the Canadian Association of Petroleum Producers and was previously a member of the Board of Directors for the Independent Petroleum Association of Mountain States in the United States.

Gregory K. Melchin became a director of Baytex on May 20, 2008. Mr. Melchin was a member of the Legislative Assembly of Alberta from 1997 to March 2008. Among his various assignments with the Government of Alberta, he was Minister of Energy, Minister of Seniors and Community Supports and Minister of Revenue. Prior to being elected to the Legislative Assembly of Alberta, he served in various management positions for twenty years in the Calgary business community. Mr. Melchin holds a Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. He has also completed the Directors Education Program with the Institute of Corporate Directors.

Dale O. Shwed became a Director of Baytex on June 3, 1993. He has held the position of President and Chief Executive Officer of Crew Energy Inc., a public oil and gas company, since September 2003. Prior thereto, he was President and Chief Executive Officer of Baytex from 1993 to August 2003. Mr. Shwed holds a Bachelor of Science degree specializing in Geology.

W. Derek Aylesworth joined Baytex as Chief Financial Officer in November 2005, and is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management, tax and treasury functions. Prior to joining Baytex, Mr. Aylesworth held the position of Commercial Manager of the Ecuador Region business unit at EnCana Corporation. Prior thereto, he was the Division Vice President for the International New Ventures Exploration business unit of the same company. Mr. Aylesworth has over 20 years of experience in the Canadian oil and gas industry. Mr. Aylesworth holds a Bachelor of Commerce degree and is a chartered accountant with expertise in taxation and has experience as a tax advisor in both the oil and gas industry and public practice in Calgary.

Randal J. Best was appointed Senior Vice President, Corporate Development of Baytex in December 2006 and is responsible for asset and corporate acquisitions and divestitures, corporate planning and reserves. Prior thereto, he was Vice President, Corporate Development of Baytex since September 2003. From 2000 to 2003 he was Managing Director of Waterous Securities, a private oil & gas investment bank specializing in mergers and acquisitions, and previous to that he was President and Chief Executive Officer of Enercap Corporation, a private investment company. Mr. Best has over 25 years of experience in the Canadian oil and gas industry and is a professional engineer. He holds a Bachelor of Applied Science degree in Chemical Engineering from the University of Waterloo and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Stephen Brownridge was appointed Vice President, Heavy Oil on December 1, 2006. Mr. Brownridge has over 20 years experience in the Canadian oil and gas industry. He joined Baytex in 1997 and held the position of Manager of the Heavy Oil Business Unit from September 2003 to December 2006. Prior to joining Baytex, Mr. Brownridge held technical positions with Koch Exploration Canada Corporation and Rigel Oil and Gas Ltd. Mr. Brownridge holds a Bachelor of Science degree with Honours in Geology from the University of Manitoba, and a Master of Science Degree in Geology obtained jointly from the University of Alberta and Louisiana State University.

Brett J. McDonald was appointed Vice President, Land on December 1, 2006. Mr. McDonald has over 25 years of experience in the Canadian oil and gas industry. He joined Baytex in 2000 and held the position of General Manager of Land from September 2003 to December 2006. Prior to joining Baytex, Mr. McDonald held senior land negotiating positions with Newport Petroleum Corporation, Stampeder Exploration Ltd. and Murphy Oil Company Ltd. Mr. McDonald is a member of the Canadian Association of Petroleum Landmen.

Timothy R. Morris joined Baytex as Managing Director, U.S. Business Development in April 2007 and was appointed Vice President, U.S. Business Development on November 12, 2007. Prior to joining Baytex, Mr. Morris was Vice President, Land and Administration of Berco Resources, LLC since 2000. Mr. Morris has over 31 years of experience in the United States oil and gas industry. Prior to working with Berco, he held senior management positions with Santa Fe Snyder Corporation, Snyder Oil Corporation, Petroleum, Inc. and Sohio Petroleum Corp. He received a Bachelor of Science degree with an area of emphasis in Minerals Land Management from the University of Colorado and is a Certified Professional Landman. He is an active member of the Independent Petroleum Association of Mountain States, Denver Association of Petroleum Landmen and the American Association of Professional Landmen.

R. Shaun Paterson was appointed Vice President, Marketing on December 11, 2006, and is responsible for the transportation and marketing of Baytex's production and implementing its commodity price risk mitigation strategies. Mr. Paterson has over 29 years of experience in the Canadian oil and gas industry. Prior to joining Baytex, he worked for EnCana Corporation as Vice President of Domestic Crude Oil Marketing. Prior to this assignment, Mr. Paterson held senior marketing and business development positions with Dynegy and Chevron. Mr. Paterson holds a Bachelor of Science degree in Mechanical Engineering from the University of Alberta.

Marty L. Proctor joined Baytex as Chief Operating Officer on January 14, 2009. Mr. Proctor has over 25 years of experience in the Canadian and international oil and gas industries, with particular emphasis in heavy oil operations. Prior to joining Baytex, he was Senior Vice President responsible for upstream operations for StatoilHydro Canada. Prior to that, Mr. Proctor was Senior Vice President of North American Oil Sands Corporation and Vice President of Murphy Oi Company. Earlier in his career, he held technical and management positions with Maxx Petroleum, Central Resources (USA), BP Resources Canada and Husky Oil. Mr. Proctor earned both Bachelor and Master of Science degrees in Petroleum Engineering from the University of Alberta, where his research focused on thermal oil recovery. He began his career in the oil and gas business working as a roughneck on drilling rigs in Alberta, British Columbia, and northern Canada. Mr. Proctor is a practicing member of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta, and is a member of the Canadian Heavy Oil Association and the Society of Petroleum Engineers.

Mark F. Smith joined Baytex as Vice President, Conventional Oil and Gas on November 20, 2006. Mr. Smith has over 25 years of industry experience primarily focused in the Western Canadian Sedimentary Basin. Prior to joining Baytex, Mr. Smith was Vice President, Development of the North Business Unit of Burlington Resources Canada/ConocoPhillips Canada. Prior to this assignment, Mr. Smith held a variety of management and operations positions with Burlington Resources Canada and Poco Petroleums Ltd. Mr. Smith holds a Bachelor of Chemical Engineering Science Degree from the University of Western Ontario and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Shannon M. Gangl has been the Corporate Secretary of Baytex since July 25, 2003. She is a partner at Burnet, Duckworth & Palmer LLP and focuses in the areas of mergers and acquisitions, oil and gas transactions and other commercial matters. She was admitted to the Alberta bar in 1993. She is a member of various professional associations such as the Law Society of Alberta, the Canadian Bar Association and the Calgary Bar Association. She obtained a Bachelor of Laws degree from the University of Victoria and a Bachelor of Commerce degree from the University of Alberta.

Ownership of Securities by Management

As at February 28, 2009, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,080,318 Trust Units, or approximately 1.1 percent of the issued and outstanding Trust Units. No Convertible Debentures were owned by this same group.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

No director or executive officer of Baytex (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Baytex), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as disclosed above under "*Additional Information Respecting Baytex Energy Ltd. – Management of the Trust* ", no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of to materially affect control of us, is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Baytex) that, while that 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-manager or trustee appointed to hold its assets or has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver-manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

In addition, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of to materially affect control of us, has 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 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.

Conflicts

There are potential conflicts of interest to which the directors and officers of Baytex will be subject in connection with the operations of Baytex. In particular, certain of the directors and officers of Baytex are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Baytex and us or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex and us. Conflicts, if any, will be subject to the procedures and remedies available under the *Business Corporations Act* (Alberta). The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director will disclose his interest in such contract or agreement and will refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the *Business Corporations Act* (Alberta).

Personnel

As at December 31, 2008, Baytex employed 141 head office employees and 45 field office employees.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The text of the Audit Committees' Mandate and Terms of Reference is attached as Appendix C.

Composition of the Audit Committee

The members of our Audit Committee are Naveen Dargan, R.E.T. (Rusty) Goepel and Gregory K. Melchin, each of whom is "independent" and "financially literate", with the meaning of National Instrument 52-110 "Audit Committees". The relevant education and experience of each Audit Committee member is outlined below:

Name	Independent	Financially Literate	Relevant Education and Experience
Naveen Dargan	Yes	Yes	Bachelor of Arts (Honours) degree in Mathematics and Economics, Master of Business Administration degree and Chartered Business Valuator designation. Independent businessman since June 2003; prior thereto Senior Managing Director and Head of Energy Investment Banking of Raymond James Ltd.
R.E.T. (Rusty) Goepel	Yes	Yes	Bachelor of Commerce (Honours) degree. Senior Vice President of Raymond James Ltd.
Gregory K. Melchin	Yes	Yes	Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. Also completed the Directors Education Program with the Institute of Corporate Directors. Member of the Legislative Assembly of Alberta from 1997 to March 2008. Prior to being elected to the Legislative Assembly of Alberta, served in various management positions for 20 years in the Calgary business community.

Pre-Approval of Policies and Procedures

Although the Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services by our auditors, it does pre-approve all non-audit services to be provided to us and our subsidiaries by the external auditors. The pre-approval for recurring tax and tax-related services is provided on an annual basis and other services are subject to pre-approval as required.

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by Deloitte & Touche LLP, our external auditors, during fiscal 2008 and 2007:

		Aggregate fees billed ($000s)	
		2008	2007
& #160;	Audit Fees	$ 1,124	$ 851
Audit-Related Fees		-	-
Tax Fees		56	5
All Other Fees		84	133
		$ 1,264	$ 989

Audit Fees. Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly results, services in this category for fiscal 2008 and 2007 also include the reviews of comment letters from Canadian and U.S. regulatory agencies, amounts for audit work performed in relation to the requirements of Section 404 of the *Sarbanes-Oxley Act of 2002* relating to internal control over financial reporting and review of prospectuses related to an acquisition and equity and debt issuances.

Audit-Related Fees. Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees.

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

All Other Fees. During fiscal 2008 and 2007, the services provided in this category consisted only of advisory services associated with property taxes.

BAYTEX SHARE CAPITAL

Baytex is authorized to issue an unlimited number of common shares and an unlimited number of Exchangeable Shares. As of the date hereof, we were the sole holder of the issued and outstanding common shares of Baytex and there were no Exchangeable Shares outstanding.

The following is a summary of certain provisions of the share capital of Baytex. For a complete description of the share provisions, reference should be made to the Articles of Baytex, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 5, 2008).

Common Shares

Each Baytex common share entitles its holders to receive notice of and to attend all meetings of the shareholders of Baytex and to one vote at such meetings. The holders of common shares will be, at the discretion of the Board of Directors and subject to applicable legal restrictions, and subject to certain preferences of holders of Exchangeable Shares, entitled to receive any dividends declared by the Board of Directors on the common shares to the exclusion of the holders of Exchangeable Shares, subject to the proviso that no dividends will be paid on the common shares unless all declared dividends on the outstanding Exchangeable Shares have been paid in full. The holders of common shares are entitled to share equally in any distribution of the assets of Baytex upon the liquidation, dissolution, bankruptcy or winding-up of Baytex or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to the Exchangeable Shares and any other shares having priority over the common shares. As at December 31, 2008, all of the common shares of Baytex are owned by us.

Exchangeable Shares

Each Exchangeable Share has economic rights (including the right to have the Exchange Ratio adjusted to account for distributions paid to Unitholders) and voting attributes (through the benefit of the Special Voting Units) equivalent to those of the Trust Units into which they are exchangeable from time to time. In addition, holders of Exchangeable Shares have the right to receive Trust Units at any time in exchange for their Exchangeable Shares, on the basis of the Exchange Ratio in effect at the time of the exchange. Holders of Exchangeable Shares do not receive cash distributions.

On May 30, 2008, the Trust announced that Baytex had elected to redeem all of its Exchangeable Shares outstanding on August 29, 2008 for Trust Units based on the Exchange Ratio in effect on August 28, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such Exchangeable Shares. As a result, as at December 31, 2008, there were no Exchangeable Shares outstanding.

MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on the Toronto Stock Exchange and the New York Stock Exchange under the trading symbols BTE.UN and BTE, respectively. The Convertible Debentures are listed and posted for trading on the Toronto Stock Exchange under the trading symbol BTE.DB.

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Trust Units, as reported by the Toronto Stock Exchange and the New York Stock Exchange for the periods indicated. The Trust Units commenced trading on the Toronto Stock Exchange on September 8, 2003 and on the New York Stock Exchange on March 27, 2006.

	Toronto Stock Exchange			New York Stock Exchange		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($US)	Low ($US)	Volume Traded
2003	10.89	9.19	40,973,662	-	-	-
2004	14.00	9.78	93,252,808	-	-	-
2005	18.78	12.42	87,481,272	-	-	-
2006	28.66	16.81	102,652,240	25.87	16.63	21,496,200
2007	22.92	16.68	86,185,013	21.74	15.51	18,062,500
2008						
January	20.08	16.30	8,450,915	20.30	15.88	1,550,400
February	21.51	17.54	7,664,775	22.00	17.37	1,507,100
March	23.40	20.22	9,631,945	23.34	20.33	1,693,100
April	26.50	22.60	10,428,318	26.35	21.90	1,459,700
May	30.63	24.38	11,361,346	31.08	23.90	1,806,900
June	35.37	28.31	12,992,517	34.98	28.09	1,723,200
July	35.01	27.77	11,828,510	35.20	27.57	4,026,107
August	32.50	28.26	7,657,965	31.33	26.55	2,184,663
September	31.40	23.15	12,133,861	29.22	22.35	4,028,994
October	27.05	15.01	13,840,975	25.49	12.65	6,992,149
November	22.00	15.05	7,500,940	19.14	11.72	3,493,110
December	18.45	12.81	9,925,351	14.44	10.16	4,012,617
2009						
January	17.49	14.20	10,049,252	14.85	11.55	3,687,803
February	14.46	9.77	13,997,248	11.95	7.84	4,270,423

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Convertible Debentures as reported by the Toronto Stock Exchange for the periods indicated. The Convertible Debentures commenced trading on the Toronto Stock Exchange on June 6, 2005.

	Price Range		
	High ($)	Low ($)	Volume Traded
2005			
0 ; 60;	127.00	99.50	76,697.5
2006	190.88	114.83	55,069.8
2007 60;	150.00	115.00	2,874.5
2008			
January 60;	135.00	121.50	336.0
February &# 160; ;	144.22	123.00	210.0
March ; &# 160;	158.26	142.19	854.0
April 60;	175.00	152.39	754.0
May 60;	200.00	165.99	917.0
June 60;	235.24	190.02	1,158.0
July 60;	230.71	193.89	374.0
August 0; & #160;	210.00	200.00	199.0
September 60;	210.00	167.41	101.0
October 60;	155.27	112.75	388.0
November 60;	129.00	105.03	12.0
December 60;	112.34	94.60	40.0
2009 60;			
January 60;	104.32	100.00	12.0
February &# 160;	100.00	93.03	155.0

RATINGS

In June 2008, Dominion Bond Rating Service Limited (" **DBRS**") assigned to us a stability rating of STA-5 (low), an upgrade from the previous rating of STA-6 (high). The stability rating is based on a rating scale developed by DBRS that provides an indication of both the stability and sustainability of an income fund's distributions per unit. Stability rating categories range from STA-1 to STA-7, with STA-1 being the highest and STA-7 being the lowest possible rating. DBRS further separates the ratings into high, middle and low to indicate relative standing within a rating category. Ratings take into consideration the seven main factors of: (1) operating and industry characteristics; (2) asset quality; (3) financial flexibility; (4) diversification; (5) size and market position; (6) sponsorship/governance; and (7) growth. In addition, consideration is given to specific structural or contractual elements that may eliminate or mitigate risks or other potentially negative factors. Income funds rated at STA-5 have weak distributions per unit stability and sustainability. These funds are subject to many of the same cyclical, seasonal, and economic factors as in the STA-4 rating category, but the lack of diversification is generally more pronounced, and will tend to be below average in several areas considered when determining a stability rating.

Baytex has been assigned a corporate family credit rating of B1 and its senior subordinated notes have been assigned a credit rating of B3, each with a stable outlook by Moody's Investor Service Inc. (" **Moody's**"). Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category.

Baytex has been assigned a corporate credit rating of BB-/Stable and its senior subordinated notes have been assigned a credit rating of B+/Stable by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**"). S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt rated "BB" is considered less vulnerable to non-payment than other speculative issues, however it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inability to meet its financial obligations. An obligation rated "B" is more vulnerable to non-payment than those rated BB, but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

The stability rating accorded to us by DBRS and the credit ratings accorded to Baytex by Moody's and S&P are not recommendations to purchase, hold or sell any of our securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we or Baytex or any subsidiary of us or Baytex is or was a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us or Baytex, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us or Baytex by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us or Baytex that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of Baytex, any holder of Trust Units who beneficially owns or controls or directs, directly of indirectly, more than 10 percent of the outstanding Trust Units, or any known associate or affiliate of such persons, in any transactions since our inception or since the beginning of our last completed financial year which has materially affected or is reasonably expected to materially affect us or Baytex.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Deloitte & Touche LLP, Chartered Accountants, Calgary, Alberta, is our auditor and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Trust Units and the Convertible Debentures.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator. None of the designated professionals of Sproule have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared a report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Baytex or of any associate or affiliate of Baytex, except for John Brussa, a director of Baytex, and Shannon Gangl, the Corporate Secretary of Baytex, who are partners at Burnet, Duckworth & Palmer LLP, a law firm that renders legal services to us.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

(a) The Trust Indenture (filed on SEDAR on June 5, 2008);

(b) the NPI Agreement (filed on SEDAR on March 16, 2009);

(c) the indenture creating the Note and the promissory note evidencing the Notes issued there under (filed on SEDAR on March 21, 2005);

(d) the indenture creating the Convertible Debentures (filed on SEDAR on June 9, 2005);

(e) our trust unit rights incentive plan (filed on SEDAR on March 26, 2009); and

(f) the credit agreement in respect of our $485 million syndicated credit facility (filed on SEDAR on March 28, 2008 and September 15, 2008).

Copies of each of these contracts are accessible on the SEDAR website at *www.sedar.com*.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by the governments of Canada, Alberta, British Columbia, Saskatchewan, the United States, North Dakota and Wyoming all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the Canadian oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the proximity, availability and lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement (" **NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Our operations which are not Crown lands and are subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and funds from operations within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently we cannot predict whether existing incentive programs will be continued or new incentive programs enacted.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 and 19% effective January 1, 2009 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008, the federal corporate income tax rate will decrease to 15% in three additional steps: 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act* , 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production rate, the density of the oil, the vintage of the oil and the selling price of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". In 1992, the Alberta Government introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates these classifications and establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008. The rates applicable to oil sands are between 1% and 9% before payout and are calculated depending on the price of WTI expressed in Canadian dollars. The royalty payable is 1% when oil is priced below or at $55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at $120 or higher. The after payout net profit interest starts at 25% and increases for every dollar when oil is priced above $55 up to 40% when oil is priced at $120 or higher.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas.

The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands (" **Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program ("**NPRP**") among others, and facilitate the development of the oil and gas industry. The NPRP's objective is to share the capital risk of successful developments. Pursuant to the *Net Profit Royalty Regulation*, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producer's interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The Government of British Columbia has introduced additional royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province of British Columbia.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.
- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate (" **RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation *Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 (" **CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO_2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol (" **Kyoto Protocol** "). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the " **Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes Greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on us and our operations and financial condition at this time.

United States

The Trust, through its subsidiary, Baytex Energy USA Ltd., also owns oil and natural gas properties and related assets in North Dakota and Wyoming in the United States. Baytex USA's oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Baytex USA's operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

ADDITIONAL INFORMATION

Additional information relating to us can be found on the SEDAR website at *www.sedar.com* and on our website at *www.baytex.ab.ca*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular - Proxy Statement for the annual and special meeting of Unitholders to be held on May 20, 2009. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2008 and the related management's discussion and analysis which are accessible on the SEDAR website at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
Form 51-101F3

Management of Baytex Energy Ltd. (" **Baytex**"), on behalf of Baytex Energy Trust (the " **Trust**"), is responsible for the preparation and disclosure of information with respect to the Trust's oil and natural 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, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Trust's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Baytex, on behalf of the Trust, has:

(a) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

(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 of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Anthony W. Marino*"	(signed) "*W. Derek Aylesworth*"
Anthony W. Marino President and Chief Executive Officer	W. Derek Aylesworth Chief Financial Officer
(signed) "*Dale O. Shwed*"	(signed) "*John A. Brussa*"
Dale O. Shwed Director and Chairman of the Reserves Committee March 9, 2009	John A. Brussa Director and Member of the Reserves Committee

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
Form 51-101F2

To the Board of Directors of Baytex Energy Ltd. (" **Baytex**"), on behalf of Baytex Energy Trust (the " **Trust**"):

1. We have evaluated the Trust's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Baytex's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with 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).

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 principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of 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 the Trust evaluated by us for the year ended December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the management and Board of Directors of Baytex:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue Before income taxes (10% discount rate – $ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2008). Prepared October 2008 to February 2009.	Canada and the United States	Nil	$3,478.8	Nil	$3,478.8

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

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 4, 2009

(signed) "*R. Keith MacLeod*"
R. Keith MacLeod, P.Eng.
President

(signed) "*Peter C. Sidey*"
Peter C. Sidey, P.Eng.
Associate

(signed) "*Michael W. Maughan*"
Michael W. Maughan, C.P.G., P.Geol.
Vice-President, Geoscience

APPENDIX C

BAYTEX ENERGY LTD.
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Baytex Energy Ltd. ("Baytex") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Baytex Energy Trust (the "Trust") and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

MEMBERSHIP OF COMMITTEE

1. The Committee shall be comprised of at least three (3) directors of Baytex, none of whom are members of management of Baytex and all of whom are "independent" (within the meaning of National Instrument 52-110 "Audit Committees" ("NI 52-110").
2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.
3. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in NI 52-110.

MEETINGS

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.
2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the audit Committee consider appropriate.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to the Trust's Internal Control Systems:
   - identifying, monitoring and mitigating business risks; and
   - ensuring compliance with legal, ethical and regulatory requirements.
3. It is a primary responsibility of the Committee to review the annual financial statements of the Trust prior to their submission to the board of directors for approval. The process should include but not be limited to:
   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.
4. The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of the Trust's disclosure of all other financial information and shall periodically access the accuracy of those procedures.
5. With respect to the appointment of external auditors by the board, the Committee shall:
   - recommend to the board the appointment of the external auditors;
   - recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
   - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors; and
   - determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

6. Review with external auditors (and internal auditor if one is appointed by the Trust) their assessment of the internal controls of the Trust, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Trust and its subsidiaries.

7. The Committee must pre-approve all non-audit services to be provided to the Trust or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review risk management policies and procedures of the Trust (i.e. hedging, litigation and insurance).

9. The Committee shall establish a procedure for:

   - the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve the Trust's hiring policies regarding employees and former employees of the present and former external auditors of the Trust.

11. The Committee shall have the authority to investigate any financial activity of the Trust. All employees of the Trust are to cooperate as requested by the Committee.

12. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of the Trust without any further approval of the board.

Consolidated Financial Statements of &
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Exhibit 99.2

BAYTEX ENERGY TRUST

December 31, 2008

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Trust is responsible for establishing and maintaining adequate internal control over financial reporting over the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2008, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect the financial statement preparation and presentation.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche LLP, the Trust's Independent Registered Chartered Accountants, who also audited the Trust's Consolidated Financial Statements for the year ended December 31, 2008.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent registered chartered accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Anthony W. Marino
President and Chief Executive Officer
Baytex Energy Ltd.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Ltd.

March 16, 2009

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors of Baytex Energy Ltd. and
Unitholders of Baytex Energy Trust:

We have audited the accompanying consolidated balance sheets of Baytex Energy Trust and subsidiaries (the "Trust") as at December 31, 2008 and 2007, and the related consolidated statements of income and comprehensive income, deficit, and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these 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). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Baytex Energy Trust and subsidiaries as of December 31, 2008 and 2007 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 16, 2009, we reported separately to the Unitholders of Baytex Energy Trust on our audit, conducted in accordance with Canadian generally accepted auditing standards, of the consolidated financial statements for the same periods, prepared in accordance with Canadian generally accepted accounting principles but which excluded Note 19, Differences Between Canadian and United States Generally Accepted Accounting Principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 16, 2009 expressed an unqualified opinion on the Trust's internal control over financial reporting.

Independent Registered Chartered Accountants
Calgary, Canada
March 16, 2009

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Trust's financial statements, such as the changes described in Notes 3 and 19 to the consolidated financial statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors of Baytex Energy Ltd. and Unitholders of Baytex Energy Trust, dated March 16, 2009, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the changes are properly accounted for and adequately disclosed in the financial statements.

Independent Registered Chartered Accountants
Calgary, Canada
March 16, 2009

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors of Baytex Energy Ltd. and Unitholders of Baytex Energy Trust:

We have audited the internal control over financial reporting of Baytex Energy Trust and subsidiaries (the "Trust") as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Trust'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 on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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 Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2008 of the Trust and our report dated March 16, 2009 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to changes in accounting principles.

(signed) "*Deloitte & Touche LLP*"
Independent Registered Chartered Accountants
Calgary, Canada
March 16, 2009

Baytex Energy Trust
Consolidated Balance Sheets

As at December 31	2008	2007
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Accounts receivable	**$ 87,551**	$ 105,176
Crude oil inventory	**332**	5,997
Financial instruments (note 16)	**85,678**	-
Future tax asset (note 14)	**-**	11,525
	173,561	122,698
Petroleum and natural gas properties (note 5)	**1,601,017**	1,246,697
Goodwill	**37,755**	37,755
	$ 1,812,333	$ 1,407,150
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 164,279**	$ 104,318
Distributions payable to unitholders	**17,583**	15,217
Bank loan (note 6)	**208,482**	241,748
Financial instruments (note 16)	**-**	34,239
Future tax liability (note 14)	**25,358**	-
	415,702	395,522
Long-term debt (note 7)	**217,273**	173,854
Convertible debentures (note 8)	**10,195**	16,150
Asset retirement obligations (note 9)	**49,351**	45,113
Deferred obligations	**74**	113
Future tax liability (note 14)	**192,411**	153,943
	885,006	784,695
Non-controlling interest (note 11)	**-**	21,235
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	**1,129,909**	821,624
Conversion feature of debentures (note 8)	**498**	796
Contributed surplus (note 12)	**21,234**	18,527
Deficit	**(224,314)**	(239,727)
	927,327	601,220
	$ 1,812,333	$ 1,407,150

Commitments and contingencies (note 17)
See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Gregory K. Melchin
Director, Baytex Energy Ltd.

Baytex Energy Trust
Consolidated Statements of Income and Comprehensive Income

Years Ended December 31	2008	2007
(thousands of Canadian dollars)		
Revenue		
Petroleum and natural gas	**$ 1,159,718**	$ 745,885
Royalties	**(207,522)**	(102,805)
Gain (loss) on financial instruments (note 16)	**59,816**	(34,484)
	1,012,012	608,596
Expenses		
Operating	**172,471**	134,696
Transportation and blending	**218,706**	155,754
General and administrative	**29,603**	23,565
Unit-based compensation (note 12)	**7,812**	7,986
Interest (note 7)	**32,962**	35,162
Foreign exchange loss (gain) (note 15)	**37,746**	(32,414)
Depletion, depreciation and accretion	**223,900**	189,512
	723,200	514,261
Income before taxes and non-controlling interest	**288,812**	94,335
Tax expense (recovery) (note 14)		
Current expense	**10,177**	6,713
Future expense (recovery)	**15,383**	(49,369)
	25,560	(42,656)
Income before non-controlling interest	**263,252**	136,991
Non-controlling interest (note 11)	**(3,358)**	(4,131)
Net income / Comprehensive income	**$ 259,894**	$ 132,860

Consolidated Statements of Deficit

Years Ended December 31,	2008	2007
(thousands of Canadian dollars, except per unit data)		
Deficit, beginning of year	**$ (239,727)**	$ (198,520)
Net income	**259,894**	132,860
Distributions to unitholders	**(244,481)**	(174,067)
Deficit, end of year	**$ (224,314)**	$ (239,727)
Net income per trust unit (note 13)		
Basic	**$ 2.83**	$ 1.66
Diluted	**$ 2.74**	$ 1.60

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows

Years Ended December 31,	**2008**	2007
(thousands of Canadian dollars)		
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	**$ 259,894**	$ 132,860
Items not affecting cash:		
Unit-based compensation (note 12)	**7,812**	7,986
Unrealized foreign exchange loss (gain) (note 15)	**41,712**	(32,574)
Depletion, depreciation, and accretion	**223,900**	189,512
Accretion on debentures and notes (notes 7 & 8)	**1,681**	2,164
Unrealized (gain) loss on financial instruments (note 16)	**(119,917)**	31,320
Future tax expense (recovery)	**15,383**	(49,369)
Non-controlling interest (note 11)	**3,358**	4,131
	433,823	286,030
Change in non-cash working capital (note 15)	**38,896**	5,140
Asset retirement expenditures (note 9)	**(1,443)**	(2,442)
Decrease in deferred obligations	**(39)**	(2,278)
	471,237	286,450
Financing activities		
(Decrease) increase in bank loan	**(33,236)**	114,253
Issue of trust units, net of issuance costs (note 10)	**10,502**	147,221
Payments of distributions	**(194,728)**	(144,609)
	(217,462)	116,865
Investing activities		
Petroleum and natural gas property expenditures	**(185,083)**	(148,719)
Corporate acquisition (note 4)	**(3,934)**	(243,273)
Acquisition of working capital (note 4)	**-**	(13,229)
Acquisition of petroleum and natural gas properties	**(84,826)**	(2,877)
Proceeds on disposal of petroleum and natural gas properties	**194**	723
Change in non-cash working capital (note 15)	**19,874**	4,060
	(253,775)	(403,315)
Change in cash and cash equivalents during the year	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described in note 2.

Certain comparative figures have been reclassified to conform to the presentation adopted in the current period.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from their respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Goodwill impairment tests involve estimates of the Trust's fair value of the net identifiable assets and liabilities annually. If the fair value is less than the book value, an impairment would be recorded. Fair value of the Trust's net identifiable assets and liabilities are based on external market value and reserve estimates and the related future cash flows which are subject to measurement uncertainty.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments which have an initial maturity date at acquisition of not more than 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test ("ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the Trust. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied fair value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. The debt portion will accrete up to the principal balance at maturity. The accretion and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Asset Retirement Obligations

The Trust recognizes a liability at the discounted value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The present value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of income and comprehensive income. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

The accounts of integrated foreign operations are translated using the temporal method, whereby monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date. Non-monetary items are translated at historical rates while revenues and expenses are translated using average rates over the period. Depreciation and amortization of assets is translated at historical exchange rates at the same exchange rates as the assets to which they relate. Translation gains and losses relating to the integrated foreign operations are included in the determination of net income for the period.

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, into one of the following five categories: held-for-trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. The Trust has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash and cash equivalents and restricted cash are classified as held-for-trading and are measured at fair value which equals the carrying value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures are classified as other financial liabilities. Upon issuance, the convertible debentures were classified into equity and financial liability components on the balance sheet at their fair value. The financial liability, net of issuance costs, is accreted, which is included within interest expense over the maturity of the debentures using the effective interest rate method.

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

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Trust are related to underlying financial instruments or future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. These instruments are classified as “held-for-trading” unless designated for hedge accounting. For derivative instruments that do not qualify as hedges or are not designated as hedges, the Trust applies the fair value method of accounting by recording an asset or liability on the Consolidated Balance Sheet and recognizes changes in the fair value of the instrument in the Statement of Income and Comprehensive Income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts.

The Trust has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments. This documentation specifically ties the derivative instruments to their use and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. When specific financial instruments are executed, the Trust assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in a particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Future Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax bases of an asset or liability, using substantively enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 12. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Trust are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the year.

3. CHANGES IN ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535, Capital Disclosures, Section 3862, Financial Instruments - Disclosures and Section 3863, Financial Instruments - Presentation.

A. Capital Disclosures

Effective January 1, 2008, the Trust prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") Section 1535, "Capital Disclosures" which establishes standards for disclosing information about the Trust's capital and how it is managed. It requires disclosures of the Trust's objectives, policies and processes for managing capital, the quantitative data about what the Trust regards as capital, whether the Trust has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The only effect of adopting this standard are disclosures on the Trust's capital and how it is managed and are included in Note 18.

B. Financial Instruments - Disclosures, Financial Instruments - Presentation

Effective January 1, 2008, the Trust prospectively adopted Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations." These new accounting standards replaced Section 3861, "Financial Instruments – Disclosure and Presentation." Section 3862 requires additional information regarding the significance of financial instruments for the entity's financial position and performance, and the nature, extent and management of risks arising from financial instruments to which the entity is exposed. The additional disclosures required under these standards are included in Note 16.

C. Inventories

Section 3031 replaces the previous inventories standard and requires inventory be valued on a first-in, first-out basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

These standards were adopted prospectively.

Future Accounting Changes

A. Goodwill and Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

B. International Financial Reporting Standards ("IFRS")

In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

C. Business Combinations

In January 2009, the CICA issued Section 1582, "Business Combinations", which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

D. Consolidated Financial Statements

In January 2009, the CICA issued Sections 1601, “Consolidated Financial Statements”, and 1602, “Non-controlling Interests”, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

4. CORPORATE ACQUISITIONS

On June 4, 2008, Baytex acquired all the issued and outstanding shares of Burmis Energy Inc., a public company which had interests in certain natural gas and light oil properties located primarily in west central Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 4, 2008. In conjunction with the acquisition, Burmis Energy Inc. was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	3,934
Total purchase price	$ 180,467

Allocation of purchase price:	
Property, plant and equipment	$ 219,913
Future income taxes	(37,910)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 180,467

All of the issued and outstanding shares of Burmis were acquired on the basis of 0.1525 of a Baytex trust unit for each Burmis share, resulting in the issuance of 6,383,416 Baytex trust units valued at $23.82 per unit, which was the average closing price of Baytex trust units for the ten trading days bordering the initial public announcement of the transaction.

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which had interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502
Allocation of purchase price:	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31	
	2008	2007
Petroleum and natural gas properties	**$ 3,648,431**	$ 3,074,014
Accumulated depletion and depreciation	**(2,047,414)**	(1,827,317)
	$ 1,601,017	$ 1,246,697

In calculating the Canadian cost centre depletion and depreciation provision for 2008, $63.6 million (2007 - $65.0 million) of costs relating to undeveloped properties were excluded, while $385.0 million (2007 - $427.1 million) of future development costs were included for the purposes of the depletion and depreciation calculation. In calculating the U.S. cost centre depletion and depreciation provision for 2008, $57.6 million (2007 - $nil) of costs relating to undeveloped properties were excluded, while $56.3 million (2007 - $nil) of future development costs were included for the purposes of the depletion and depreciation calculation. No general and administrative expenses have been capitalized since the inception of operations as a trust.

Depletion and depreciation expense related to the Canadian and U.S. cost centers in 2008 were $218.4 million and $1.7 million respectively (2007 – $186.1 million and $nil).

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2008 using the following benchmark reference prices for the years 2009 to 2013 adjusted for commodity differentials specific to the Trust (notes 16 & 17):

	2009	**2010**	**2011**	**2012**	**2013**
WTI crude oil (US$/bbl)	53.73	63.41	69.53	79.59	92.01
AECO natural gas ($/MMBtu)	6.82	7.56	7.84	8.38	9.20
Henry Hub (US$/MMBtu)	6.30	7.32	7.56	8.49	9.74
Exchange rate ($US equals $1 CAD)	0.80	0.85	0.85	0.90	0.95

The prices and costs subsequent to 2013 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculations, the Trust's estimated undiscounted future net cash flows associated with proved reserves plus the cost of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN AND CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit (note 17) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. Effective June 4, 2008, total credit facilities were increased to $485 million from $370 million. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. The credit facilities mature on July 1, 2009 and are eligible for extension. At December 31, 2008 a total of $208.5 million was drawn under the credit facilities (December 31, 2007 - $241.7 million).

7. LONG-TERM DEBT

	As at December 31	
	2008	2007
10.5% senior subordinated notes (US$247)	**$ 303**	$ 244
9.625% senior subordinated notes (US$179,699)	**220,059**	177,561
	220,362	177,805
Discontinued fair value hedge	**(3,089)**	(3,951)
	$ 217,273	$ 173,854

The Company has US$0.2 million senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The Company also has US$179.7 million senior subordinated notes bearing interest at 9.625% payable semi-annually with principal repayable on July 15, 2010. These notes are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2008 at 102.406%, 2009 and thereafter at 100%. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of CICA Handbook Section 3865 "Hedges". The notes will accrete up to the principal balance at maturity using the effective interest method. Accretion expense of $1.6 million had been recorded for the year ended December 31, 2008 (December 31, 2007 - $2.0 million) The effective interest rate is 10.6%. The Company had an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2% until the maturity of these notes. In November 2007, the Company terminated the interest rate swap contract. A gain on termination of $2.0 million was recorded as a reduction to interest expense in 2007.

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

	2008	2007
Bank loan and miscellaneous financing	**$ 12,685**	$ 13,296
Convertible debentures	**945**	1,295
Long-term debt	**19,332**	20,571
Total interest	**$ 32,962**	$ 35,162

8. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010, at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statement of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Number of Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2006	19,619	$ 18,906	$ 940
Conversion	(2,999)	(2,895)	(144)
Accretion	-	139	-
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	-	97	-
Balance, December 31, 2008	**10,398**	**$ 10,195**	**$ 498**

9. ASSET RETIREMENT OBLIGATIONS

	As at December 31,	
	2008	2007
Balance, beginning of year	**$ 45,113**	$ 39,855
Liabilities incurred	**871**	2,180
Liabilities settled	**(1,443)**	(2,442)
Acquisition of liabilities	**1,536**	2,239
Disposition of liabilities	**(904)**	(585)
Accretion	**3,802**	3,404
Change in estimate[(1)]	**376**	462
Balance, end of year	**$ 49,351**	$ 45,113

[(1)] Change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2008 is $274.0 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an estimated annual inflation rate of 2.0 percent.

10. UNITHOLDERS' CAPITAL

The Trust is authorized to issue an unlimited number of trust units.

	Number of Units	Amount
Balance, December 31, 2006	75,122	$ 637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	-	2,816
Issued pursuant to distribution reinvestment plan	1,464	27,763
Cumulative effect of change in accounting policy	-	3,005
Balance, December 31, 2007	84,540	821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of trust unit rights	1,386	10,653
Transfer from contributed surplus on exercise of trust unit rights	-	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	**97,685**	**$ 1,129,909**

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 90 percent of the "market price" of the trust units on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $250,000 per month. Redemptions in excess of the cash limit, if not waived by the Trust, shall be satisfied by distribution of subordinate, unsecured redemption notes bearing interest at 12% per annum, due and payable no later than September 1, 2033.

11. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2006	1,573	$ 17,187
Exchanged for trust units	(7)	(83)
Non-controlling interest in net income	-	4,131
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	-	3,358
Balance, December 31, 2008	**-**	**$ -**

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2008, there were no exchangeable shares outstanding.

12. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of rights available to grant under the Plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $7.8 million for the year ended December 31, 2008 ($8.0 million in 2007) related to the rights granted under the plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $2.42 per unit for rights issued during 2008 ($3.87 per unit in 2007). The following assumptions were used to arrive at the estimate of fair values:

	2008	2007
Expected annual right's exercise price reduction	**$ 2.64**	$ 2.16
Expected volatility	**28% - 39%**	28%
Risk-free interest rate	**2.98% - 4.17%**	3.77% - 4.50%
Expected life of right (years)	**Various (1)**	Various (1)

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Trust Unit Rights Incentive Plan.

The number of unit rights outstanding and exercise prices are detailed below:

	Number of rights	Weighted average exercise price [1]
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	8,449	$ 14.58

[1] Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2008:

Range of Exercise Prices	Number Outstanding at December 31, 2008	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at December 31, 2008	Weighted Average Exercise Price
		(years)			
$ 1.00 to $ 6.00	706	0.9	$ 3.71	706	$ 3.71
$ 6.01 to $11.00	1,352	1.8	$ 8.35	1,254	$ 8.17
$ 11.01 to $16.00	399	3.2	$ 15.08	183	$ 15.14
$ 16.01 to $21.00	5,947	3.9	$ 17.18	1,637	$ 17.05
$ 21.01 to $32.28	45	4.4	$ 25.93	-	-
$ 1.00 to $32.28	8,449	3.3	$ 14.58	3,780	$ 11.52

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2006	$ 13,357
Compensation expense	7,986
Transfer from contributed surplus on exercise of trust unit rights [1]	(2,816)
Balance, December 31, 2007	$ 18,527
Compensation expense	7,812
Transfer from contributed surplus on exercise of trust unit rights [1]	(5,105)
Balance, December 31, 2008	$ 21,234

[1] Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

13. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

2008	Net income	Trust units	Net income per trust unit
Net income per basic unit	**$ 259,894**	**91,683**	**$ 2.83**
Dilutive effect of trust unit rights	**-**	**2,955**	
Conversion of convertible debentures	**654**	**882**	
Exchange of exchangeable shares	**3,358**	**871**	
Net income per diluted unit	**$ 263,906**	**96,391**	**$ 2.74**

2007	Net income	Trust units	Net income per trust unit
Net income per basic unit	$ 132,860	80,029	$ 1.66
Dilutive effect of trust unit rights	-	2,110	
Conversion of convertible debentures	855	1,206	
Exchange of exchangeable shares	4,131	2,630	
Net income per diluted unit	$ 137,846	85,975	$ 1.60

The dilutive effect of trust unit incentive rights for the year ended December 31, 2008 did not include 45,000 trust unit rights (2007 – 4.1 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services and not yet recognized exceeded the average market price of the trust units during the year.

14. TAX EXPENSE (RECOVERY)

The provision for (recovery of) taxes has been computed as follows:

	2008	2007
Income before taxes and non-controlling interest	**$ 288,812**	$ 94,335
Expected taxes at the statutory rate of 30.22% (2007 – 34.02%)	**87,279**	32,094
Increase (decrease) in taxes resulting from:		
Net income of the Trust	**(79,930)**	(62,615)
Non-taxable portion of foreign exchange loss (gain)	**6,204**	(5,424)
Effect of change in tax rate	**(1,402)**	(15,806)
Effect of change in opening tax pool balances	**878**	(834)
Effect of change in valuation allowance	**-**	2,075
Unit-based compensation	**2,361**	2,717
Other	**(7)**	(1,576)
Future tax expense (recovery)	**15,383**	(49,369)
Current tax expense	**10,177**	6,713
Total tax expense (recovery)	**$ 25,560**	$(42,656)

On June 22, 2007, Bill C-52 Budget Implementation Act, which contains legislative provisions to tax publicly traded income trusts in Canada, received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted, an additional future tax recovery of $0.5 million was recorded in 2007.

The components of the net future tax liability at December 31 were as follows:

	2008	2007
Future tax liabilities:		
Petroleum and natural gas properties	**$ 197,694**	$ 155,921
Financial instruments	**25,358**	-
Other	**14,215**	18,271
Future tax assets:		
Asset retirement obligations	**(12,652)**	(11,796)
Non-capital loss carry-forward	**(11,813)**	(8,058)
Valuation allowance on non-capital losses	**4,967**	-
Financial instruments	**-**	(11,525)
Other	**-**	(395)
Net future tax liability [(1)]	**217,769**	142,418
Current portion of net future tax liability (asset)	**25,358**	(11,525)
Long-term portion of net future tax liability	**$ 192,411**	$ 153,943

[(1)] Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken, amongst Canadian and U.S. subsidiaries, totaled $42.9 million ($62.0 million in 2007) and expire from 2014 to 2017.

15. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	2008	2007
Current assets	**$ 35,460**	$ (23,619)
Current liabilities	**23,310**	32,819
	$ 58,770	$ 9,200
Changes in non-cash working capital related to:		
Operating activities	**$ 38,896**	$ 5,140
Investing activities	**19,874**	4,060
	$ 58,770	$ 9,200

Supplemental Cash Flow Information

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes:

	2008	2007
Interest	**$ 30,655**	$ 32,321
Current income taxes	**$ 9,972**	$ 9,436

Foreign Exchange Loss (Gain)

	2008	2007
Unrealized foreign exchange loss (gain)	**$ 41,712**	$ (32,574)
Realized foreign exchange (gain) loss	**(3,966)**	160
Total foreign exchange loss (gain)	**$ 37,746**	$ (32,414)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial derivative contracts, long-term debt, convertible debentures and deferred obligations.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following 5 categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	December 31, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Loans and receivables				
Accounts receivable	**$ 87,551**	**$ 87,551**	$ 105,176	$ 105,176
Total loans and receivables	**$ 87,551**	**$ 87,551**	$ 105,176	$ 105,176
Held for trading				
Derivatives designated as held for trading	**$ 85,678**	**$ 85,678**	-	-
Total held for trading	**$ 85,678**	**$ 85,678**	-	-
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	**-**	**-**	$ (34,239)	$ (34,239)
Total held for trading	**-**	**-**	$ (34,239)	$ (34,239)
Other financial liabilities				
Accounts payable and accrued liabilities	**$ (164,279)**	**$ (164,279)**	$ (104,318)	$(104,318)
Distributions payable to unitholders	**(17,583)**	**(17,583)**	(15,217)	(15,217)
Bank loan	**(208,482)**	**(208,482)**	(241,748)	(241,748)
Long-term debt	**(217,273)**	**(200,557)**	(173,854)	(182,132)
Convertible debentures	**(10,195)**	**(9,837)**	(16,150)	(19,481)
Deferred obligations	**(74)**	**(74)**	(113)	(113)
Total other financial liabilities	**$ (617,886)**	**$ (600,812)**	$ (551,400)	$(563,009)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan, and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long-term debt is based on the trading value of the instrument. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows associated with the debentures.

Financial Risk

The Trust is exposed to a variety of financial risk, including market risk, credit risk and liquidity risk. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk
The Trust is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated notes, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Trust's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

In order to manage these risks, the Trust may enter into agreements to fix the exchange rate of Canadian to U.S. dollar in order to lessen the impact of currency rate fluctuations.

At December 31, 2008, the Trust had in place the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	CAD/USD 1.2394 (weighted average)

The following table demonstrates the effect of exchange rate movement on net income before taxes and non-controlling interest due to changes in the fair value of its currency swap as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2008.

	$0.10 Increase/Decrease in CAD/USD Exchange Rate
Gain/loss on currency swap	$ (189)
Gain/loss on other monetary assets/liabilities	10,939
Impact on income before taxes and non-controlling interest	$ 10,750

The carrying amounts of the Trust's foreign currency denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2008	December 31, 2007	December 31, 2008	December 31, 2007
U.S. dollar denominated	USD 84,070	USD 54,674	USD 191,571	USD 226,528

Subsequent to December 31, 2008, the Trust added the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345

Interest rate risk
The Trust's interest rate risk arises from its floating rate bank loan. As at December 31, 2008, $208.5 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 1.0% in interest rates would impact cash flow for the 2008 by approximately $2.2 million.

Commodity Price Risk
The Trust monitors and, when appropriate, utilizes financial derivative agreements or fixed price physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of the Company. Under the Trust's risk management policy, financial instruments are not used for speculative purposes.

When assessing the potential impact of commodity price changes, a 10% increase in commodity prices could have resulted in a reduction to the unrealized gain in 2008 of $8.5 million relating to the financial derivative instruments outstanding as at December 31, 2008, while a 10% decrease could have resulted in $8.8 million of additional gain.

At December 31, 2008, the Trust had the following commodity derivative contracts:

OIL	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – 136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – 172.70	WTI

Derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	2008	2007
Realized (loss) on financial instruments	**$ (60,101)**	$ (3,164)
Unrealized gain (loss) on financial instruments	**119,917**	(31,320)
Gain (loss) on financial instruments	**$ 59,816**	$ (34,484)

Subsequent to December 31, 2008, the Trust added the following commodity derivative contract:

GAS	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – 6.30	AECO

Liquidity risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. As at December 31, 2008, the Trust had available unused bank credit facilities in the amount of $183 million. The Trust believes it has sufficient funding capacity through its credit facilities to meet foreseeable borrowing requirements.

The timing of cash outflows (excluding interest) relating to financial liabilities are outlined in the table below:

	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	-	-	-
Distributions payable to unitholders	17,583	17,583	-	-	-
Bank loan [1]	208,482	208,482	-	-	-
Long-term debt [2]	220,362	-	220,362	-	-
Convertible debentures [2]	10,398	-	10,398	-	-
Deferred obligations	74	46	23	5	-
	621,178	390,390	230,783	5	-

[1] The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.
[2] Principal amount of instruments.

Credit risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at December 31, 2008, accounts receivable consists of a balance of $9.9 million which is over 90 days (December 31, 2007 - $3.5 million). A balance of $2.4 million has been set up as an allowance for doubtful accounts (December 31, 2007 - $0.2 million).

17. COMMITMENTS AND CONTINGENCIES

At December 31, 2008, the Trust had the following crude oil supply contracts:

Heavy Oil	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)

Subsequent to December 31, 2008, the Trust added the following physical crude oil supply contracts:

Heavy Oil	Period	Volume	Price
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI x 80.0%
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI less US$10.00

At December 31, 2008, the Trust had the following natural gas physical sales contract:

Gas	Period	Volume	Price/GJ
Price Collar	Calendar 2009	5,000 GJ/d	$7.00 - $7.95

At December 31, 2008, the Trust had the following power contracts:

Power	Period	Volume	Price/MWh
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$79.92

Subsequent to December 31, 2008, the Trust added the following physical power contract:

Power	Period	Volume	Price/MWh
Fixed	March 1, 2009 to June 30, 2010	0.6 MW/hr	$76.89

At December 31, 2008, the Trust had operating lease and transportation obligations as summarized below:

	Payments Due						
	Total	1 year	2 years	3 years	4 years	5 years	Beyond 5 years
Operating leases	$ 42,732	$ 2,776	$ 3,327	$ 3,785	$ 4,073	$ 3,814	$ 24,957
Processing and transportation agreements	22,350	8,478	7,435	6,196	178	63	-
Total	$ 65,082	$ 11,254	$ 10,762	$ 9,981	$ 4,251	$3,877	$ 24,957

Other

At December 31, 2008, there were outstanding letters of credit aggregating $2.3 million (December 31, 2007 - $4.9 million) issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at December 31, 2008, additional payments totaling $5.3 million have been paid under the agreement and have been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

18. CAPITAL STRUCTURE

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new units, issue new debt or sell assets to reduce debt.

The Trust monitors capital based on current and projected ratios of total monetary debt to cash flow, and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to cash flow from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to cash flow from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to cash flow from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its cash flow from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank loan, senior subordinated notes and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbor amount. The safe harbor amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbor amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006/2007 and $365 million for each of the subsequent three years. The safe harbor amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth. At December 31, 2008, the Trust had not exceeded its "normal growth" limits.

19. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are described in this note.

Reconciliation of net income under Canadian GAAP to U.S. GAAP

For the years ended December 31		**2008**	2007
	Note		
Net income – Canadian GAAP		**$ 259,894**	$ 132,860
Increase (decrease) under U.S. GAAP:			
Unrealized gain (loss) on financial instruments	D	**-**	(1,168)
Depletion, depreciation and accretion	A, H	**(695,715)**	34,741
Interest	D	**959**	2,351
Unit-based compensation	C	**(1,206)**	3,149
Income tax recovery (expense)	A,D,H,I	**160,235**	(16,703)
Non-controlling interest	B	**3,358**	4,131
Net income (loss) – U.S. GAAP		**$ (272,475)**	$ 159,361
Net income (loss) per trust unit	K		
Basic		**$ (2.94)**	**$ 1.93**
Diluted		**$ (2.94)**	**$ 1.86**
Weighted average trust units	K		
Basic		**92,554**	**82,659**
Diluted		**92,554**	**85,975**

Condensed Consolidated Statement of Operations – U.S. GAAP

For the years ended December 31	Note	**2008**	2007
Revenue			
Petroleum and natural gas sales, net of royalties		**$ 952,196**	$ 643,080
Gain (loss) on financial instruments	D	**59,816**	(35,652)
		1,012,012	607,428
Expenses			
Operating	C	**174,445**	135,700
Transportation and blending		**218,706**	155,754
General and administrative	C	**36,647**	27,398
Interest	D	**32,003**	32,891
Foreign exchange loss (gain)		**37,746**	(32,494)
Depletion, depreciation and accretion	A,H	**919,615**	154,771
		1,419,162	474,020
Income (loss) before taxes		**(407,150)**	133,408
Current		**10,177**	6,713
Future	A,D,H,I	**(144,852)**	(32,666)
Tax recovery		**(134,675)**	(25,953)
Net income (loss)/ Comprehensive Income (loss)		**$ (272,475)**	$ 159,361

Consolidated Statement of Accumulated Deficit		
Deficit, beginning of the year	**$ (1,159,401)**	$ (1,403,144)
Net income (loss)	**(272,475)**	159,361
Distributions to unitholders	**(244,481)**	(174,067)
Adjustment for fair value of temporary equity	**469,564**	258,449
Deficit, end of the year	**$ (1,206,793)**	$ (1,159,401)

Condensed Consolidated Balance Sheet

As at December 31		**2008**		2007	
	Note	**As Reported**	**U.S. GAAP**	As Reported	U.S. GAAP
Assets					
Current assets	D,I	**$ 173,561**	**$ 173,561**	$ 122,698	$ 122,674
Petroleum and natural gas properties	F	**3,648,430**	**3,548,224**	3,074,014	3,058,163
Accumulated depletion & depreciation	A	**(2,047,413)**	**(2,844,948)**	(1,827,317)	(1,929,982)
Petroleum and natural gas properties, net		**1,601,017**	**703,276**	1,246,697	1,128,181
Deferred charges	H	**-**	**2,059**	-	3,016
Goodwill		**37,755**	**37,755**	37,755	37,755
		$ 1,812,333	**$ 916,651**	$ 1,407,150	$ 1,291,626
Liabilities and Unitholders' Equity					
Current liabilities	D	**$ 415,702**	**$ 390,344**	$ 395,522	$ 395,522
Long-term debt	D	**217,273**	**220,362**	173,854	177,805
Convertible debentures	E	**10,195**	**10,398**	16,150	16,620
Deferred obligations		**74**	**74**	113	113
Asset retirement obligations		**49,351**	**49,351**	45,113	45,113
Share-based payment liability	C	**-**	**21,825**	-	35,909
Future tax liability	A,D,H,I	**192,411**	**-**	153,943	123,737
		885,006	**692,354**	784,695	794,819
Non-controlling interest	B	**-**	**-**	21,235	-
Temporary equity		**-**	**1,431,090**	-	1,656,208
Unitholders' capital	B	**1,129,909**	**-**	821,624	-
Conversion feature of debentures	E	**498**	**-**	796	-
Contributed surplus	B,C	**21,234**	**-**	18,527	-
Deficit		**(224,314)**	**(1,206,793)**	(239,727)	(1,159,401)
		927,327	**(1,206,793)**	601,220	(1,159,401)
		$ 1,812,333	**$ 916,651**	$ 1,407,150	$ 1,291,626

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

For the years ended December 31	**2008**	2007
Operating activities		
Net income (loss)	**$ (272,475)**	$ 159,361
Unit-based compensation	**9,018**	4,837
Amortization of deferred charges	**845**	1,385
Unrealized foreign exchange loss (gain)	**42,434**	(32,574)
Depletion, depreciation and accretion	**918,770**	153,199
Unrealized (gain) loss on financial derivatives	**(119,917)**	32,488
Future tax (recovery)	**(144,852)**	(32,666)
Change in non-cash working capital	**38,896**	5,140
Asset retirement expenditures	**(1,443)**	(2,442)
Decrease in deferred charges and other assets	**(39)**	(2,278)
Cash from operating activities	**$ 471,237**	$ 286,450
Cash (used in) financing activities	**$ (217,462)**	$ 116,865
Cash (used in) from investing activities	**$ (253,775)**	$ (403,315)

Notes:

(A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP and U.S. GAAP differs in the following respects. Under U.S. GAAP, the book value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent, (based on prices and costs at the balance sheet date) plus the lower of cost and fair value of unproven properties including the cost of properties not being amortized. The cost of properties not being amortized consists of the cost of acquiring and evaluating undeveloped land.

Under Canadian GAAP the first stage of this “ceiling test” is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the petroleum and natural gas assets are impaired. An impairment loss exists when the book value of the petroleum and natural gas assets exceeds such undiscounted cash flows. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceed the future discounted cash flow from proved plus probable reserves at forecast prices.

In computing its consolidated net income for U.S. GAAP purposes in prior years, the Trust recorded additional depletion as a result of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes and therefore the charge for depletion, depreciation and accretion will differ in subsequent years.

At December 31, 2008, the Trust’s capitalized costs of oil and gas properties exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $799.1 million charged to depletion, depreciation and accretion (2007 – nil). As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

Under Canadian GAAP, depletion is calculated by reference to proved reserves estimated using forecast prices. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices. The difference in proved reserves has resulted in $104.3 million less depletion recorded under U.S. GAAP for the year ended December 31, 2008 ($36.1 million less depletion – 2007).

(B) Temporary Equity

The Trust Units contain a redemption feature which is required for the Trust to retain its mutual fund trust status for Canadian income tax purposes. The redemption feature of the trust units entitles the holder to redeem the Trust Units. However, the restrictions on redemption are not substantive enough to be accounted for as a component of permanent Unitholders' Equity under U.S. GAAP, in accordance with EITF D-98, "Classification and Measurement of Redeemable Securities", the trust units must be presented as Temporary Equity and recorded on the consolidated balance sheets at their redemption value.

In applying EITF D-98 the Trust has recorded Temporary Equity in the amount of $1,431.1 million as at December 31, 2008 and $1,656.2 million as at December 31, 2007 which represents the estimated redemption value of the Trust Units and the exchangeable shares (which are convertible into trust units) at the balance sheet date. The difference between the Trust's Temporary Equity under U.S. GAAP and Unitholders' Capital under Canadian GAAP is applied to Accumulated Deficit. The adjustments to Accumulated Deficit are credits of $469.6 million for 2008 and $258.4 million for 2007.

Under Canadian GAAP, the exchangeable shares of the Trust are presented as a non-controlling interest on the consolidated balance sheet. Net income under Canadian GAAP has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet.

Under U.S. GAAP, the consolidated balance sheet would not include an amount for non-controlling interest and income would not be reduced. Instead, under U.S. GAAP, the estimated redemption amount of the exchangeable shares at the balance sheet date would be included in Temporary Equity on the consolidated balance sheet.

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share had been exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2008, there were no exchangeable shares outstanding.

(C) Unit-Based Compensation

The Trust has a Trust Units Rights Incentive Plan established in 2003. As the exercise price of the unit rights granted under the plan is subject to downward revisions from time to time, the unit rights plan is a variable compensation plan under U.S. GAAP. Effective January 1, 2006, the Trust adopted Statement of Financial Accounting Standards No. 123R "Share-Based Payments", (SFAS 123R) for purposes of the U.S. – Canadian GAAP reconciliation using modified prospective application. Under this standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. The fair value of the unit rights has been determined using a binomial-lattice model. Under SFAS 123R the Trust's share-based compensation plan is classified as a liability and the unit rights are fair valued at each reporting date. Compensation expense for the unit rights plan is recognized in income until settlement date based on the reporting date fair value and the portion of the vesting period that has transpired. The accounting for compensation expense for the unit rights plan results in a difference between Canadian and U.S. GAAP, as the Trust classifies the unit rights plan as equity awards and uses the grant date fair value method to account for its unit compensation expense under Canadian GAAP. Under U.S. GAAP compensation expense was increased by $1.2 million in 2008 ($3.1 million reduction to compensation expense in 2007).

(D) Derivative Instruments and Hedging
On January 1, 2007, under Canadian GAAP, the Trust adopted CICA Handbook Section 1530 “Comprehensive Income”, Section 3251 “Equity”, Section 3855 “Financial Instruments – Recognition and Measurement”, Section 3861 “Financial Instruments – Disclosure and Presentation”, and Section 3865 “Hedges”. These standards were adopted retrospectively and the comparative consolidated financial statements have not been restated. Transitional amounts were recorded in deficit.

Prior to the adoption of the above standards, the Trust applied hedge accounting to its interest rate swap and as such did not record a financial asset or liability relating to the hedging instrument (the swap). Upon adoption of these standards, the Trust chose to discontinue hedge accounting on its interest rate swap and recorded a financial liability on the balance sheet January 1, 2007 with the a corresponding deferred adjustment being recorded as a reduction in the US$ notes. Changes in the fair value of the swap are recorded in net income. The deferred loss will be amortized for Canadian GAAP over the life of the notes. Under U.S. GAAP hedge accounting was never applied to the interest rate swap and the U.S. dollar notes and as such the U.S. notes are increased for the remaining deferred adjustment of $3.9 million and interest expense decreased by $0.9 million for the current year accretion of the deferred adjustment ($2.0 million in 2007). The interest rate swap was terminated November 29, 2007. As at December 31, 2008 and December 31, 2007 no additional liability was recorded under U.S. GAAP.

Under Section 3855, physical commodity contracts which are entered into and continue to be held for the purposes of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements are excluded from the requirements of Section 3855 provided the price is not based on a variable that is not closely related to the asset being purchased sold or used and they are documented as such. Upon the adoption of Section 3855 on January 1, 2007, the Canadian-U.S. GAAP difference has been eliminated and no additional financial asset or liability has been recognized for U.S. GAAP at December 31, 2008 or December 31, 2007.

(E) Convertible Debentures
Under Canadian GAAP, the Trust’s convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete the balance to the principal due on maturity.

Under U.S. GAAP, the convertible debentures in their entirety are classified as debt. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP. As a result $0.5 million has been reclassified to liabilities from equity ($0.8 million in 2007) and $0.1 million of non-cash interest expense has been reversed ($0.3 million in 2007).

(F) Step Acquisition on Exchange of Exchangeable shares
Under Canadian GAAP, when the exchangeable shares are exchanged for Trust Units, the transaction is treated as a step acquisition whereby petroleum and natural gas properties are increased by the difference between the fair value of the exchangeable shares and their carrying value, tax effected. The offset is credited to future tax liability and Trust units. Under U.S. GAAP the exchangeable shares are considered to be a component of temporary equity and therefore no business combination is considered to have occurred. The cumulative effect of the reversal of the step acquisition is a reduction in petroleum and natural gas properties of $84.4 million (2007 – $14.8 million) and a decrease in future tax liability of $22.1 million (2007 - $5.8 million).

(**G) Other Comprehensive Income**
Statement of Financial Accounting Standards No. 130 "Comprehensive Income" requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income. Management has concluded that Baytex has no other comprehensive income; accordingly comprehensive income is equivalent to net income.

(H) Deferred Charges
On January 1, 2007 under Canadian GAAP, the Trust adopted Section 3855. Under this standard, the Trust elected to expense all financial instrument transaction costs immediately. Transactions costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. Under U.S. GAAP, transaction costs continue to be deferred and amortized over the life of the related asset or liability. Under U.S. GAAP there is an asset of $2.1 million on the balance sheet as at December 31, 2008 (2007 - $3.0 million). Additional amortization expense of $0.8 million has been recognized in net income ($1.4 million in 2007).

(I) Income Taxes
Under U.S. GAAP, enacted tax rates are used to calculate current and future taxes; whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the Reconciliation of Net Income under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

On January 1, 2007, the Trust adopted for U.S. GAAP purposes, FASB Interpretation No. 48 “Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109”. The Trust has applied the same guidance in assessing its uncertain tax positions under Canadian GAAP.

Baytex and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Trust has substantially concluded all Canadian federal and provincial income tax matters for the years through 2004. Substantially all U.S. federal income tax matters remain open.

(J) Consolidated Statement of Cash Flows
Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

(K) Earnings Per Share
Under Canadian GAAP, basic net income per unit is calculated based on net income after non-controlling interest divided by weighted average units and diluted net income per unit is calculated based on net income before non-controlling interest divided by dilutive units. Under U.S. GAAP, since the exchangeable shares are classified in the same manner as the trust units, basic net income per unit is calculated based on net income divided by weighted average units and the unit equivalent of the outstanding exchangeable shares.

(L) Business Combinations
Under SFAS 141, “Business Combinations”, supplemental pro forma disclosure is required for significant business combinations occurring during the year. On June 4, 2008 the Trust completed a business combination as well as on June 26, 2007. The following unaudited pro forma information provides an indication of what the Trust’s results of operations might have been under U.S. GAAP had the business combination taken place on January 1, of each of the following years:

(unaudited)	**2008 Pro Forma**	2007 Pro Forma
Oil and gas sales	**1,196,599**	837,807
Net (loss) income	**(281,457)**	158,014
Net (loss) income per trust unit:		
Basic	**$ (2.96)**	$ 1.71
Diluted	**$ (2.96)**	$ 1.66

(M) Additional Disclosures

i. The components of accounts receivable are as follows:

As at December 31	**2008**	2007
Oil & gas sales and accrual	**62,926**	83,907
Joint venture	**23,755**	15,946
Prepaids and deposits	**3,280**	2,809
Other	**-**	2,714
Less: allowance for doubtful accounts	**(2,410)**	(200)
	87,551	105,176

ii. The components of accounts payable are as follows:

As at December 31	**2008**	2007
Contractors and vendors	**76,629**	59,601
Accrued liabilities	**87,650**	44,717
	164,279	104,318

Recent Developments in U.S. Accounting
In February 2007, FASB issued SFAS No. 159 “The Fair Value Option for Financial Assets and Financial Liabilities – Including Amendment of FASB Statement No. 115”, which allows an entity to choose to measure many financial instruments and certain other items at fair value for fiscal years beginning on or after November 15, 2007. The Company has not been materially impacted by SFAS No. 159.

As of January 1, 2008, the Trust adopted, for U.S. GAAP purposes, SFAS 157, “Fair Value Measurements”. SFAS 157 provides a common definition of fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This standard applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The adoption of this standard did not have a material impact on consolidated financial statements of the Trust.

In May 2008, the FASB issued Statement of Financial Accounting Standards No. 162, “The Hierarchy of Generally Accepted Accounting Principles”. This standard became effective November 15, 2008 following the SEC’s approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section, 411 “The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles”. The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. GAAP. The adoption of this standard did not have a material impact on the consolidated financial statements of the Trust.

The Trust has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Trust:

- As of January 1, 2009, the Trust will be required to adopt, for U.S. GAAP purposes, SFAS 141(R), “Business Combinations”, which replaces SFAS 141. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard will impact the Trust’s U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.

- As of January 1, 2009, the Trust will be required to adopt, for U.S. GAAP purposes, SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51”. This standard requires a noncontrolling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP Consolidated Statement of Earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the noncontrolling interest and to disclose these respective amounts. The adoption of this standard should not have a material impact on the consolidated financial statements of the Trust.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 40-F for the year ended December 31, 2009. Adoption of the new rules may impact results of future ceiling tests for the Trust as the pricing may result in significant difference in future net revenue from reserves.

Exhibit 99.3

Management's Discussion and Analysis

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust for the year ended December 31, 2008. This information is provided as of March 16, 2009. In this MD&A, references to "Baytex", the "Trust", "we", "us" and "our" and similar terms refer to Baytex Energy Trust and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Trust's audited consolidated comparative financial statements for the years ended December 31, 2008 and 2007, together with accompanying notes, and Annual Information Form for the year ended December 31, 2008. These documents and additional information about the Trust are available on SEDAR at www.sedar.com.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on Generally Accepted Accounting Principles in Canada ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, asset retirement expenditures, and decrease in deferred obligations. The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income. For a reconciliation of cash flow from operations to cash flow from operating activities, see "Cash Flow from Operations, Payout Ratio and Distributions".

2008 OVERVIEW

Baytex Energy Trust is an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to a trust indenture. Baytex was established on September 2, 2003 in connection with a Plan of Arrangement of our subsidiary, Baytex Energy Ltd. (the "Company"). Through our subsidiaries, we are actively engaged in the exploration, development and production of oil, natural gas and natural gas liquids in Canada in the provinces of British Columbia, Alberta and Saskatchewan and in the United States in North Dakota and Wyoming.

Our business objective has been to maintain production levels through investing approximately half of our internally generated cash flow while distributing the balance of our cash flow to holders of our trust units. Over our life, we have grown our reserve base and added to production levels through exploration and development activities complimented by strategic acquisitions.

During 2008, the Trust executed a successful capital program (excluding acquisitions) resulting in the replacement of 119% of production (on a proved plus probable basis) by spending 43% of cash flow from operations. When acquisitions are included, the Trust replaced 233% of production by spending 63% of cash flow.

As at December 31 2008, we had a reserve base of 187 million (gross) boe on a proved plus probable basis. During the year ended December 31, 2008, our production averaged 40,239 boe/d primarily in Canada, with minor amounts of production contributed from our U.S. operations.

On June 4, 2008, we acquired all of the issued and outstanding shares of Burmis Energy Inc.("Burmis") on the basis of 0.1525 of a Baytex trust unit for each Burmis common share. Approximately 6.38 million Baytex trust units were issued to acquire Burmis. Pursuant to this transaction, we acquired multi-zone, liquids-rich natural gas and light oil properties located in west central Alberta and approximately 110,300 net acres of undeveloped land. Production from the Burmis properties averaged 3,791 boe/d during the first quarter of 2008.

During the third quarter of 2008, we reached agreement to acquire a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in North Dakota from a private company. Upon making all deferred payments associated with the transaction, we will have acquired a 37.5% interest in 263,000 gross acres (approximately 98,625 net acres). At the time of the acquisition, 94% of the lands were undeveloped. In addition, we acquired approximately 300 boe/d (95% oil) of company interest production. The seller retained the remaining 62.5% interest in the project lands and production.

PROPERTY REVIEW

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2008, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Conventional Oil and Gas and U.S. business units. Each business unit has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these business units, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Baytex invested approximately $82 million in land over the past two years targeting three light oil resource plays. These plays include the Bakken / Three Forks in the Williston Basin of North Dakota, the Viking in southwestern Saskatchewan and eastern Alberta and a Mowry Shale exploratory play in the Powder River Basin of eastern Wyoming. These light oil resources plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

Heavy Oil Business Unit

The Heavy Oil business unit accounts for more than 55% of current production and more than 65% of oil-equivalent reserves. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 250 bbl/d of crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2008, production in the Heavy Oil business unit averaged approximately 23,530 bbl/d of heavy oil and 6,654 Mcf/d of natural gas (24,639 Boe/d). Baytex drilled 111 (103.8 net) wells in the Heavy Oil business unit resulting in 105 (97.8 net) oil wells, 4 (4.0 net) stratigraphic test wells, and 2 (2.0 net) dry and abandoned wells, for a success rate of 98%.

The Heavy Oil business unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore and Peace River in Alberta. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of our large inventory of heavy oil projects, we are able to select from a wide range of investment opportunities to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's historical area of emphasis around Lloydminster. Our net undeveloped lands in the Heavy Oil business unit totalled approximately 348,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Heavy Oil Business Unit:

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2008 was approximately 1,395 bbl/d of oil and 455 Mcf/d of natural gas (1,471 boe/d). Seven successful oil wells and no dry holes were drilled in the area during 2008. Baytex anticipates drilling four wells in this area in 2009. Due to extensive Baytex infrastructure in this area, operating expenses in 2008 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2008.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. No new wells were drilled in 2008, but 4 re-completions were conducted. Despite the absence of new well drilling, year-over-year production decline was only about 8% due mostly to strong performance of the ongoing waterflood. Average production in 2008 was approximately 2,115 bbl/d of heavy oil and 650 Mcf/d of natural gas (2,224 boe/d). Net undeveloped lands were 9,900 acres at year-end 2008.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 4,670 bbl/d of heavy oil and 1,118 Mcf/d of natural gas (4,856 boe/d) during 2008. (This production number includes very minor production in the area held prior to the Celtic acquisition). Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2009, Baytex expects to drill 10 new wells and re-complete approximately 45 existing wells. Net undeveloped lands were 8,800 acres at year-end 2008.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2008 was approximately 507 bbl/d. Baytex drilled two successful oil wells in the Cold Lake area in 2008, and we plan to drill three new wells in the area in 2009. Net undeveloped lands were 13,600 acres at year-end 2008.

Dodsland, Saskatchewan: During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 API) oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex targeted the less permeable but undeveloped areas of the play and drilled a 1,400 metre horizontal well in 2008. The horizontal well was completed with 7 fracture stimulations, applying the same multi-zone fracture technology that is used to stimulate horizontal wells in the Bakken oil play in southeast Saskatchewan and North Dakota. At year-end 2008, Baytex had leased 34,600 net acres in the play. Ultimately, up to 150 wells may be drilled on these lands.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2008 was approximately 3,380 bbl/d of oil and 831 Mcf/d of natural gas (3,518 boe/d). Twenty-three successful oil wells were drilled in this region in 2008. In addition, a significant facility expansion involving water flow-lining and conservation of the solution gas was completed. This project has reduced operating costs in the area and tied-in approximately 300 mcf/d of solution gas into the local sales network. For 2009, a further 14 wells are planned. Net undeveloped lands were 26,300 acres at year-end 2008.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in 105 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced using horizontal wells at initial rates of 150 to 250 bbl/d per well, without employing more cost-intensive methods such as steam injection. In 2008, Baytex drilled four stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 19 horizontal production wells in 2008, bringing the total number of producing wells to 44. The average production rate during 2008 was 3,707 bbl/d of heavy oil. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase economic oil reserves beyond what is achievable with cold primary recovery. A cyclic steam pilot project was carried out on an existing horizontal producer during 2008 to validate the numerical reservoir simulation models. Due to the positive results from our steam pilot, the year-end 2008 reserve report included an assignment for thermal reserves at Seal for the first time. This reserve assignment supports our assessment that commercial cyclic steam development at Seal is economically viable. Seal area facilities were expanded in 2008 by constructing a water disposal plant and a fuel gas supply pipeline. Operating costs for primary production are forecasted to remain very low at $4 to $5/bbl and the gas pipeline ensures an adequate fuel supply for future thermal development of the property. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2009, Baytex plans to drill two additional stratigraphic test wells and 14 additional cold horizontal production wells. Net undeveloped lands were 65,000 acres at year-end 2008.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of re-completion opportunities. In 2008, the company drilled 3 wells and a further 15 wells were either re-started or re-completed to a new zone. Average production during 2008 was approximately 1,626 bbl/d of heavy oil and 915 Mcf/d of natural gas (1,779 boe/d). In 2009, Baytex plans to re-work or re-complete about 15 existing wells. Net undeveloped lands were 7,100 acres at year-end 2008.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.25% working interest. Company-interest production is approximately 800 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. Nine (1.9 net) wells were drilled in this area in 2008. Baytex expects the field operator to maintain a level of activity that would result in an approximately flat production rate. Net undeveloped lands were 11,000 acres at year-end 2008.

Conventional Oil and Gas Business Unit

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties. In addition to Baytex's historical light oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Conventional Oil and Gas business unit produces light and medium gravity crude oil, natural gas and natural gas liquids (“NGL”) from various fields in Alberta and British Columbia. During 2008, production from this business unit averaged 48,066 Mcf/d of natural gas sales and 7,401 bbl/d of light oil and NGL (15,412 boe/d). During 2008, the Conventional business unit drilled 31 (21.4 net) wells resulting in 18 (11.9 net) gas wells, 7 (4.1 net) oil wells, 2 (1.4 net) service wells, and 4 (4.0 net) dry holes for a success rate of 87.1% (81.3% net). Our net undeveloped lands in this business unit were approximately 329,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Conventional Oil and Gas Business Unit:

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2008, production for the area averaged approximately 2,524 Mcf/d of gas and 264 bbl/d of light oil (685 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2008, Baytex drilled two (1.75 net) oil wells in this area. At year-end 2008, Baytex had 11,500 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2008 averaged approximately 2,209 Mcf/d of gas (368 boe/d). At year-end 2008, Baytex had 18,100 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 4,109 Mcf/d of gas and 11 bbl/d of NGL (696 boe/d) during 2008 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2008, Baytex participated in the drilling of 4 operated and 1 non-operated locations, resulting in 4 (2.9 net) producing gas wells and 1 (1.0 net) dry hole. At year-end 2008, Baytex had 11,700 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its initial position in Pembina in June 2007 and further expanded its presence in the area through the acquisition of Burmis in June 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations including the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2008, Pembina production averaged 4,062 bbl/d of light oil and NGL and 13,272 Mcf/d of gas (6,274 boe/d). Baytex participated in drilling 6 (5.0 net) operated and 2 (0.6 net) non-operated locations in 2008. Four wells (2.3 net) were drilled to test Nisku prospects, resulting in 1 (0.6 net) oil well, 1 (0.4 net) gas well and 2 (1.4 net) service wells. Four (3.3 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2008, resulting in 3 (3.0 net) gas wells and 1 (0.25 net) dry hole. The 2009 drilling program for Pembina will include up to three wells to evaluate Nisku prospects and four wells for multi-zone Cretaceous potential. During the first quarter of 2009, Baytex will be constructing a pipeline in the Pembina O'Chiese area to increase gas volumes delivered to market and improve netback prices for our Pembina production. At year-end 2008, Baytex had 32,600 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001, and significantly increased its presence with a 2004 acquisition of a private company. During 2008, production averaged approximately 5,971 Mcf/d of sales gas and 11 bbl/d of NGL (1,006 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas produced from this area is processed at two Baytex-operated gas plants. During 2008, Baytex drilled 5 (1.7 net) wells in this area, resulting in 3 (1.5 net) gas wells and 2 (0.2 net) oil wells. At year-end 2008, Baytex had 29,200 net undeveloped acres in this area.

Red Earth/Goodfish/Lafond, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2008 averaged approximately 4,058 Mcf/d of gas and 770 bbl/d of light oil and NGL (1,446 boe/d). During 2008, Baytex drilled 4 (3.1 net) wells in this area, resulting in 1 (0.5 net) oil well, 1 (0.6 net) gas well, and 2 (2.0 net) dry holes. At year-end 2008, Baytex had 28,600 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2008 averaged approximately 8,375 Mcf/d of gas and 1,392 bbl/d of oil and NGL (2,788 boe/d). Baytex drilled 3 (2.4 net) wells in 2008 resulting in 1 (1.0 net) oil well, 1 (0.4 net) gas well, and 1 (1.0 net) dry hole. During 2009, Baytex plans to drill two wells in the area. At year-end 2008, Baytex had 32,000 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2008 averaged approximately 519 bbl/d of oil and NGL and 1,383 Mcf/d of gas (750 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2008, Baytex drilled one (0.1 net) gas well in this area. At year-end 2008, Baytex had 9,600 net undeveloped acres in this area.

United States Business Unit

Through our wholly-owned subsidiary, Baytex Energy USA Ltd. ("Baytex USA"), we acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. During 2008, Baytex USA drilled and/or acquired an interest in 34 (12 net) wells and increased its acreage position to over 120,000 net acres. Net production from the United States properties averaged 188 boe/d in 2008, and 339 boe/d in December 2008.

Listed below is a brief description of the principal properties within the United States Business Unit:

Williston Basin – Bakken/Three Forks Project: This light oil resource play is located in the Divide and Burke Counties of North Dakota. Production is primarily from horizontal wells using multi-zone hydraulic fracturing in the Bakken and Three Forks formations. Both zones are accessed through a single horizontal lateral. Baytex USA has invested in approximately 251,000 (94,000 net) acres of land. In 2008, Baytex USA participated in 8 gross (3 net) wells. Baytex USA also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. This survey was 73% complete at the end of 2008. Net production from the project was approximately 341 boe/d in the fourth quarter of 2008. In 2009, Baytex USA plans to drill 6 gross (2.25 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial rates expected to be 190 boe/d or more per well and average recoveries expected to be 280 mboe/well or more.

Powder River Basin – Mowry Shale Play (Wild West): In September 2007, Baytex USA acquired its initial leasehold interest in this Mowry shale play covering approximately 15,300 (9,200 net) acres. A vertical well (Baytex USA 60% working interest) was drilled in 2008 to acquire core and ultimately serve as a microseismic monitoring well for subsequent horizontal-well fracturing. Completion of the vertical well, including hydraulic fracturing, is scheduled for the first quarter of 2009. Baytex USA views horizontal, multi-zone hydraulically-fractured wells as the most promising method to ultimately develop the Mowry, although there have been no horizontal wells drilled in the project area to-date. A horizontal well is planned to further evaluate the prospect in 2009. Ultimately, the project may include up to 60 horizontal wells.

MARKETING

Crude Oil

The year 2008 was marked by the unprecedented volatility in world oil prices. Early in the year strong worldwide oil demand growth coupled with limited spare production capacity pushed prices to all time highs. During the fourth quarter demand for oil collapsed on the back of plunging economic conditions which were exacerbated by high energy prices. Inventories swelled reflecting demand destruction and naturally prices fell steeply. The ongoing sub-prime mortgage and credit crisis created much uncertainty in the financial and commodity markets, adding to price weakness and volatility. For the most part, these financial considerations overshadowed geopolitical events in spite of the protracted conflicts in Iraq and Afghanistan and the fear of Iran's potential entry into the world's nuclear club.

Prices for New York Mercantile exchange traded West Texas Intermediate ("WTI"), the benchmark for Canadian crude oil sales, peaked at US$147.27 per barrel on July 11th and plunged to a low for the year on December 19th of US$33.87 per barrel – a staggering 77% decline from the peak. This represents the largest crude oil price drop in history. World demand for oil and products decreased to 85.8 million barrels per day (according to the International Energy Agency) from 86.0 million barrels a day in 2007. United States demand alone dropped by 0.5 million barrels a day over the year. Weather was not a significant factor in 2008 despite some refinery shut downs in the U.S. Gulf Coast which caused local refined product shortages in September due to hurricanes. Hurricane activity did not significantly affect critical U.S. Gulf Coast crude oil or natural gas production facilities.

Benchmark WTI prices averaged US$99.59 per barrel during 2008 which obscures the drastic monthly changes in the market during the fourth quarter. The price in 2008 was on average 38% higher than 2007 when the price averaged US$72.31 per barrel. The 5-year WTI average is US$67.22 per barrel.

Canadian Par crude at Edmonton averaged $102.86 per barrel in 2008 versus $76.35 per barrel in 2007, up 33% for the year. The 5-year Canadian Par average price is $74.55 per barrel.

Canadian heavy sour crude price differentials were generally much tighter this year at 23% of WTI than the previous five-year average of 33%. Again the extremes were severe in 2008 between the highs at 46% in December and the low of 14% during the summer. We believe that the December differential was anomalous due to the lag between negotiated fixed differentials in the market and the month of delivery drop in benchmark WTI prices. The December fixed differentials were negotiated in mid-November when they would have provided a 24% differential, but WTI dropped precipitously (by over US$15.00 per barrel) into the delivery month of December. We believe that Canadian heavy sour crude price differentials will remain low through 2010.

Baytex's conventional light crude oil and NGL prices averaged $88.92 before hedging, 36% higher than the $65.53 per barrel we received in 2007. For portions of 2008, the Canadian light sweet crude oil prices were depressed due to logistical challenges and competitive market pressures from new U.S. Bakken production.

Our heavy oil wellhead prices averaged $65.22 per barrel in 2008, 47% higher than the $44.28 per barrel we received in 2007 due to fundamental changes in the supply/demand balance for Canadian heavy crude oil. Several refineries completed heavy crude oil conversion projects in the markets served by Canadian heavy crude and supply growth out of the Western Canadian Sedimentary Basin was muted due to high costs and poor project delivery performance. This combination along with improved pipeline access and capacity meant that Canadian heavy crude was in good demand. Diluent premiums also decreased over the period which contributed to improved netbacks for Canadian heavy crude. As mentioned above, the market was disappointed by marginal increases in heavy crude supply at the same time much rail receipt capacity was added to bring in U.S. sourced diluent (condensate and naphtha). Further, the price of U.S. naphthas and natural gasoline was depressed due to a worldwide oversupply of waterborne naphtha-like material due to new NGL liquefaction projects. The net result was a significant decrease in Canadian diluent prices, which is a significant cost input to production of Canadian heavy crude oil blends.

In October and November of 2007, Baytex entered into physical heavy sour crude oil sales agreements with four parties. The contracts required Baytex to deliver 15,340 bbl/d of Lloydminster Blend or Western Canadian Select ("WCS") heavy crude oil blend for 2008, and 10,340 bbl/d for 2009. Prices received from these agreements average 68% of WTI in 2008 and 67% in 2009. In January 2009, we added two physical heavy sour crude oil sales agreements to contribute to the management our heavy oil pricing volatility exposure by selling 775 bbl/d of WCS heavy crude oil to counterparty at WTI minus a fixed US$10.00 per barrel and 775 bbl/d at 80% of delivery month WTI. These agreements commence April 1, 2009 and terminate August 31, 2009. The cumulative affect of these agreements significantly reduces the volatility of Baytex's cash flows from heavy crude oil sales.

WTI costless collars have been put in place for 2009 on 4,000 barrels per day at a weighted average price from US$100.00 per barrel to US$154.55 per barrel. No collars or any other hedging instruments have yet been implemented for 2010.

The market and infrastructure solutions for our Seal area remain a work-in-progress. Long-term logistical solutions are being developed for the area. Pembina Pipeline announced on August 12, 2008 that they are installing two pipelines to serve the area by mid-2011. The first pipeline will provide 100,000 bbl/d of blended heavy crude oil capacity to the Edmonton market. The second pipeline will provide 22,000 bbl/d of condensate/diluent supply to the Nipisi/Seal region for use in blending bitumen to pipeline viscosity specifications. Both lines can be expanded by 50%. This new capacity should open up existing capacity on the Rainbow Pipeline operated by Plains Marketing which also serves the region. Plains Marketing is also considering providing condensate/diluent service to the area. Baytex does not have term transportation obligations in place with either party.

Natural Gas

Natural gas prices in North America weakened in 2008 due to a significant growth in U.S. domestic natural gas supply and, later in the year, reduced demand due to a slumping economy. In 2007, natural gas prices were negatively affected in the latter half of the year as some three Bcf/d of liquefied natural gas ("LNG") was imported during the summer months into the U.S. from foreign sources. During 2008, LNG did not enter the market in significant quantities, but this was completely offset by growth of 6% or 3.3 Bcf/d in domestic U.S. gas production. The new production came from the Rockies basin and the new shale basins in Texas and Louisiana. It is expected that demand will be lost in the coming year due to low industrial and commercial demand due to a weak economy.

During the first half of 2008, high oil prices sustained natural gas prices at levels that might have been much lower in a lower alternative energy price environment. Second half gas prices were negatively impacted as the general economic environment deteriorated, and industrial demand collapsed. U.S. gas prices peaked at US$12.96 per MMBtu in July and dipped to close the year at US$6.47 per MMBtu. U.S. natural gas inventories continue to stay within the five year average. In addition to the new supply from U.S. sources, there was little in the way of any weather related disruptions as suffered during the 2005 hurricane season. U.S. gas prices represented by the NYMEX futures contract, averaged US$9.03 per MMbtu in 2008, an increase of 32% from US$6.86 per MMbtu in 2007 – all on the back of higher crude oil prices. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.15 per Mcf in 2008, up 27% from $6.44 per Mcf in 2007. The five-year averages are US$7.57 per MMBtu for the NYMEX contract, and $7.27 per Mcf for Alberta daily prices. We expect gas drilling to drop off throughout North America which, along with general improvement in the continental economy, will bring the supply/demand picture into better balance by 2010.

For 2008, Baytex had entered into several physical forward sales contracts with price collars. Baytex received an average of $7.92 per Mcf for 2008 natural gas sales compared to $6.61 per Mcf in 2007, a 7% increase. Baytex entered into one natural gas collar for calendar 2009 for a volume of 4,739 Mcf/d with a floor (put price) of $7.39 per Mcf and a ceiling (call price) of $8.39 per Mcf.

OPERATIONS

Production

The Trust's average production for fiscal 2008 was 40,239 boe/d compared to 36,222 boe/d for fiscal 2007.

For the year ended December 31, 2008, light oil and NGL production increased by 39% to 7,575 bbl/d from 5,483 bbl/d for last year. The increase primarily resulted from the inclusion of full-year results from the Pembina assets acquired in June 2007 and from the acquisition of Burmis Energy Inc. in June 2008. Heavy oil production for 2008 increased by 7% to 23,530 bbl/d, as compared to 22,092 bbl/d for 2007. The increase in heavy oil production stemmed from development activities and the inclusion of full-year production from the Lindbergh assets acquired in June 2007. Natural gas production increased by 6% to average 54.8 MMcf/d for 2008 compared to 51.9 MMcf/d for 2007 due largely to the Pembina and Burmis acquisitions in June 2007 and 2008, respectively.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (MMcf/d)	Oil Equivalent (boe/d)
2008				
Heavy Oil Business Unit	-	23,530	6.7	24,639
Conventional Oil and Gas Business Unit	7,575	-	48.1	15,600
Total Production[(1)]	7,575	23,530	54.8	40,239
2007				
Heavy Oil Business Unit	-	22,092	7.3	23,315
Conventional Oil and Gas Business Unit	5,483	-	44.6	12,907
Total Production	5,483	22,092	51.9	36,222

(1) Per unit calculations throughout the MD&A are based on sales volumes, which differ from production volumes due to changes in inventory balances related to heavy oil, as discussed below.

Revenue

Petroleum and natural gas sales for 2008 increased by 55% to $1,159.7 million from $745.9 million for fiscal 2007. Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for 2008 were 300 bbl/d higher (2007 – 340 bbl/d higher) than the production for the period due to changes in inventory.

Benchmark WTI crude oil averaged US$99.59 per barrel for 2008, representing a 38% increase over the US$72.31 per barrel for 2007. The Trust's light oil and NGL price averaged $88.92 per barrel for 2008, representing a 36% increase over the 2007 price of $65.53 per barrel. The heavy oil price increased 46% to $65.22 per barrel in 2008 from $44.53 per barrel in 2007. Natural gas prices were 20% higher in 2008, averaging $7.92 per Mcf compared to $6.61 per Mcf during the previous year.

For 2008, light oil and NGL revenue increased 88% from the same period last year due to a 36% increase in wellhead prices and a 38% increase in sales volume. Revenue from heavy oil increased 56% due to a 46% increase in wellhead prices and a 7% increase in sales volume. Revenue from natural gas production increased 27% compared to 2007, as production increased 6% combined with a price increase of 20%.

During 2008, sulphur production averaged 48.9 tonnes per day with an average price of $381 per tonne. In prior years, sulphur revenue was not material for reporting purposes.

During the first quarter of 2008, Baytex received a $2.0 million payment from a company as compensation for non-performance of a drilling obligation which was reported as other income under petroleum and natural gas sales.

	2008		2007	
	$ thousands	**$/Unit[1]**	$ thousands	$/Unit[1]
Oil revenue				
Light oil & NGL	**246,516**	**88.92**	131,143	65.53
Heavy oil [2]	**568,841**	**65.22**	364,581	44.53
Total oil revenue	**815,357**	**70.94**	495,724	48.65
Natural gas revenue	**158,845**	**7.92**	125,235	6.61
Total oil and gas revenue	**974,202**	**65.66**	620,959	46.53
Sulphur revenue	**6,820**		-	
Other income	**2,000**		-	
Sales of heavy oil blending diluent	**176,696**	**110.30**	124,926	82.94
Total petroleum and natural gas sales	**1,159,718**		745,885	

[1] Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.

[2] Heavy oil wellhead prices are net of blending costs.

Financial Instruments

The gain on financial instruments for the year ended December 31, 2008 was $59.8 million, as compared to a loss of $34.5 million in 2007. For 2008, this is comprised of $60.1 million in realized loss and $119.9 million in unrealized gain, as compared to $3.2 million in realized loss and $31.3 million in unrealized loss in 2007.

Royalties

For the year ended December 31, 2008, royalties increased to $207.5 million from $102.8 million for last year. Royalties for 2008 include $0.9 million related to the production of sulphur. Total royalties in 2008 were 21% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% of sales for 2007. For 2008, royalties were 23% of sales for light oil, NGL and natural gas and 20% for heavy oil (excluding sales of heavy oil diluent), as compared to 19% and 15%, respectively, for the same period in 2007. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume escalate. Heavy oil royalties as a percentage of revenue were higher in the year as market prices, on average, were higher than the prices realized by Baytex under fixed differential supply agreements. Heavy oil royalties also increased in 2008 as certain oilsands projects at Seal and Cold Lake reached payout, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the year ended December 31, 2008 increased to $172.5 million from $134.7 million in 2007. Operating expenses for 2008 include $0.3 million related to the production of sulphur. Operating expenses were $11.62 per boe for 2008 as compared to $10.09 per boe for the prior year. In 2008, operating expenses were $11.68 per boe of light oil, NGL and natural gas and $11.55 per barrel of heavy oil as compared to $9.61 and $10.40, respectively, in 2007. In the case of light oil, NGL and natural gas, increased operating expense was driven primarily by increases in costs for third-party processing (including prior-period adjustments), fuel, power and labor. In the case of heavy oil, increased operating expense was due primarily to increased fluid hauling charges, and higher property taxes. Heavy oil operating expense was also negatively impacted by inclusion of higher-cost production at Lindbergh for the full year.

Transportation and Blending Expenses

Transportation and blending expenses for the year ended December 31, 2008 were $218.7 million compared to $155.8 million for 2007. Transportation expense for 2008 included $1.3 million related to the transportation of sulphur. Transportation expenses were $2.83 per boe in 2008 compared to $2.31 per boe in 2007. Transportation expenses were $0.64 per boe of light oil, NGL and natural gas and $4.22 per barrel of heavy oil in 2008, compared to $0.80 and $3.26, respectively, in 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and fuel costs which increased by over 25% from 2007 to 2008. In 2008, the blending cost was $176.7 million for the purchase of 4,377 bbl/d of condensate at $110.30 per barrel, as compared to $124.9 million for the purchase of 4,127 bbl/d at $82.94 per barrel in 2007.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of its heavy oil. The cost of diluent is effectively recovered in the sale price of a blended product.

Net Revenue

	Light Oil & NGL ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGL ($/bbl)		Natural Gas ($/Mcf)		BOE ($/boe)	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Sales price [1]	**88.92**	65.53	**65.22**	44.53	**70.94**	48.65	**7.92**	6.61	**65.66**	46.53
Royalties	**(22.97)**	(12.99)	**(12.93)**	(6.68)	**(15.35)**	(7.91)	**(1.50)**	(1.17)	**(13.92)**	(7.70)
Operating costs	**(12.38)**	(10.79)	**(11.55)**	(10.40)	**(11.75)**	(10.48)	**(1.85)**	(1.48)	**(11.60)**	(10.09)
Transportation	**(0.47)**	(0.66)	**(4.22)**	(3.26)	**(3.31)**	(2.75)	**(0.13)**	(0.15)	**(2.74)**	(2.31)
Net revenue	**53.10**	41.09	**36.52**	24.19	**40.53**	27.51	**4.44**	3.81	**37.40**	26.43

[1] Sales price is before realized loss/gain recognized on financial derivative contracts and sulphur production and is net of blending costs for heavy oil.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2008 were $29.6 million, compared to $23.6 million for the prior year. On a per sales unit basis, these expenses were $2.00 per boe in 2008 and $1.77 per boe in 2007. The increase is attributable to escalating costs in the labor market and additional expenses associated with a new office in Denver to manage the U.S. operations. In accordance with our full cost accounting policy, no expenses were capitalized in either 2008 or 2007.

($ thousands)	**2008**	**2007**
Gross corporate expense	**37,554**	32,132
Operator's recoveries	**(7,950)**	(8,567)
Net expenses	**29,604**	23,565

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $7.8 million for the year ended December 31, 2008 compared to $8.0 million for 2007.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expense

For the year ended December 31, 2008, interest expense was $33.0 million compared to $35.2 million for last year. Interest expense was affected by a more favorable exchange rate on the U.S. dollar denominated interest expense and through lower interest on reduced bank borrowings. These factors were partially offset by accretion of the discontinued fair value hedge.

Foreign Exchange

The foreign exchange loss for the year ended December 31, 2008 was $37.7 million compared to a gain of $32.4 million in the prior year. The 2008 loss is comprised of an unrealized foreign exchange loss of $41.7 million and a realized foreign exchange gain of $4.0 million. The 2007 gain was substantially unrealized. The 2008 unrealized loss stemmed from the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 1.0120 CAD/USD at December 31, 2007. The 2007 unrealized gain was based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 0.8581 CAD/USD at December 31, 2006.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $223.9 million for the year ended December 31, 2008 compared to $189.5 million for 2007. On a sales-unit basis, the provision for the current year was $15.09 per boe compared to $14.20 per boe for 2007. The higher rate is primarily due to the acquisition of Burmis in June 2008.

Taxes

On June 22, 2007, the Federal Government's bill regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received Royal Assent. See "— Federal Government's Trust Tax Legislation." As a result, we recognized a future income tax recovery of $0.5 million in the second quarter of 2007 relating to unutilized tax pools which will be deductible to us after 2010. The majority of our temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

Current tax expense for the year ended December 31, 2008 is comprised of $10.2 million of Saskatchewan capital tax and resource surcharge. The 2007 current tax expense included $7.2 million of Saskatchewan capital tax and resource surcharge, and a recovery of $0.5 million relating to a prior period.

The fiscal 2008 provision for future taxes was an expense of $15.4 million compared to a recovery of $49.4 million for the prior year. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 - $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 - $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 - $153.9 million). The increase from the prior year is due to future tax liability recognized on the Burmis acquisition of $37.9 million and current year provision of $25.4 million attributable to the unrecognized gain on financial instruments of $119.9 million.

As a result of the Pembina/Lindbergh acquisition in 2007, Baytex recognized a future tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Federal Tax Pools

($ thousands)	**2008**	**2007**
Cumulative Canadian Exploration Expense	**53,047**	36,872
Cumulative Canadian Development Expense	**193,319**	183,910
Cumulative Canadian Oil and Gas Property Expense	**217,260**	187,899
Undepreciated Capital Cost	**249,306**	217,939
Other	**27,741**	19,827
Total Canadian tax pools	**740,673**	646,447
U.S. tax pools	**116,785**	2,132

Net Income

Net income for the year ended December 31, 2008 was $259.9 million compared to $132.9 million for 2007. The increase is the result of increased production, increased sales prices and unrealized gain on financial instruments, partially offset by increased royalties, and increased loss on foreign exchange and depletion.

Cash Flow from Operations

Cash flow from operations in 2008 increased 52% to $433.8 million from $286.0 million for the previous year. The increase is primarily due to higher production volumes and a 38% increase in average WTI oil price in 2008 compared to 2007. On a barrel of oil equivalent basis, cash flow from operations was $29.46 per boe for 2008 compared to $21.63 per boe for 2007.

Cash Distributions

During 2008, total cash distributions of $2.64 per unit were declared. The monthly cash distribution in 2008 was increased from $0.18 per unit to $0.20 per unit in March and then to $0.25 per unit in June. Distributions were decreased in December 2008 to $0.18 per unit and in February 2009 to $0.12 per unit.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital, asset retirement expenditures, and deferred obligations. The Trust's payout ratio is calculated as cash distributions (net of participation in our Distribution Reinvestment Plan ("DRIP")) divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to cash flow from operations (a non-GAAP measure):

For the years ended December 31 ($ thousands)	2008	2007
Cash flow from operating activities	**$ 471,237**	$ 286,450
Change in non-cash working capital	**(38,896)**	(5,140)
Asset retirement expenditures	**1,443**	2,442
Decrease in deferred obligations	**39**	2,278
Cash flow from operations	**$ 433,823**	$ 286,030
Cash distributions	**$ 197,026**	$ 145,927
Payout ratio	**45%**	51%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserves reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions declared, net of DRIP participation, of $197.0 million during the year 2008 were funded through cash flow from operations of $433.8 million.

The following table compares cash distributions to cash flow from operating activities and net income:

($ thousands)	**2008**	2007
Cash flow from operating activities	**$ 471,237**	$ 286,450
Cash distributions declared	**197,026**	145,927
Excess of cash flow from operating activities over cash distributions declared	**$ 274,211**	$ 140,523
Net income	**$ 259,894**	$ 132,860
Cash distributions declared	**197,026**	145,927
Excess (shortfall) of net income over cash distributions declared	**$ 62,868**	$ (13,067)

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures for exploration and development activities through cash flow from operating activities. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of lower commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing. As at December 31, 2008, Baytex had approximately $183 million in available undrawn credit facilities to fund such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the year ended December 31, 2008, the Trust's net income exceeded distributions declared by $62.9 million with net income reduced by $211.3 million of non-cash items and asset retirement expenditures. Non-cash items such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions. Other non-cash charges, such as unrealized losses on financial instruments and unrealized foreign exchange losses, reduce the net income of a current period, but may not have the same impact on future periods' cash flow. Accordingly, net income is not a fair representation of the Trust's ability to fund our distributions and capital programs.

Liquidity and Capital Resources

The current worldwide economic crisis has resulted in disruptions in the availability of credit on commercially acceptable terms. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our ongoing short, medium and long-term commitments. Specifically, we believe that our internally generated cash flow from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium, and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2008, total monetary debt was $533.0 million compared to $444.1 million at the end of 2007. Included in this increase is a $42.6 million unrealized foreign exchange loss related to the translation of our U.S. dollar denominated notes. Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures. Bank borrowings and working capital deficiency at the end of 2008 were $302.5 million compared to total credit facilities of $485.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The syndicated credit facilities were increased from $370.0 million to $485.0 million in June 2008. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. The credit facilities mature on July 1, 2009, and are eligible for extension.

Baytex's credit facilities are available pursuant to an agreement with a syndicate of nine financial institutions. Of the nine syndicate members in our facilities, five are major Canadian banks which represent $275 million or 57% of the commitments under the $485 million facilities. We have had preliminary discussions with members of our lending syndicate, and have no reason to believe that the facilities will not be extended upon maturity; however, the amount of the facilities available upon extension has not yet been determined. Under the terms of our credit agreement, we may make a formal request for extension as early as April 1, 2009. A copy of our credit agreement and the first amendment agreement is accessible on the SEDAR website at *www.sedar.com* (filed on March 28, 2008 and September 15, 2008).

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders if the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities or the U.S. dollar senior subordinated notes.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary and the Trust has the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices.

Capital Expenditures

Capital expenditures during 2008 totaled $450.2 million, with $185.1 million spent on exploration and development activities, $180.5 million on corporate acquisitions and $84.6 million spent on property acquisitions (net of dispositions). For the year ended December 31, 2008, in Canada the Trust participated in the drilling of 142 (125.8 net) wells, resulting in 113 (102.1 net) oil wells, 17 (12.3 net) gas wells, 6 (5.4 net) stratigraphic test and service wells and 6 (6.0 net) dry holes compared to prior year activities of 136 (127.9 net) wells, including 103 (98.3 net) oil wells, 20 (16.8 net) gas wells, 7 (6.8 net) stratigraphic test wells and 6 (6.0 net) dry holes. In the U.S., the Trust participated in the drilling of 10 (4.5 net) wells, resulting in 9 (3.6 net) oil wells and 1 (0.9 net) dry hole.

	Year Ended December 31	
($ thousands)	**2008**	**2007**
Land	**9,534**	7,253
Seismic	**4,947**	1,994
Drilling and completion	**132,296**	108,106
Equipment	**34,720**	26,624
Other	**3,586**	4,742
Total exploration and development	**185,083**	148,719
Corporate acquisition (net of working capital)	**180,467**	243,273
Property acquisitions	**84,826**	2,877
Property dispositions	**(194)**	(723)
Total capital expenditures	**450,182**	394,146

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. A significant portion of these obligations will be funded through operating cash flow. These obligations as of December 31, 2008, and the expected timing of funding of these obligations are noted in the table below.

($ thousands)	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	-	-	-
Distributions payable to unitholders	17,583	17,583	-	-	-
Bank loan [1]	208,482	208,482	-	-	-
Long-term debt [2]	220,362	-	220,362	-	-
Convertible debentures [2]	10,398	-	10,398	-	-
Deferred obligations	74	46	23	5	-
Operating leases	42,732	2,776	7,112	7,887	24,957
Processing and transportation agreements	22,350	8,478	13,631	241	-
Total	686,260	401,644	251,526	8,133	24,957

[1] The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009; however, the amount of the facilities available upon extension has not yet been determined.

[2] Principal amount of instruments.

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

The Trust also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of units. On October 18, 2004, the Trust implemented a DRIP under which Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units may be issued from treasury at 95% of the "weighted average closing price" or acquired on the market at prevailing market prices. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Non-controlling Interest

Baytex is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by Baytex for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008 of 1.79560. As at December 31, 2008, there were no exchangeable shares outstanding.

Financial Instruments and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Board of Directors of the Company (the "Board"), assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar senior subordinated notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term bankers' acceptance rates.

Details of the risk management contracts in place as at December 31, 2008, and the accounting for the Trust's financial instruments are disclosed in note 16 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2008 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 1 and 2 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. The financial and operating results of the Trust incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

The Trust has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments – Disclosures” and Section 3863 “Financial Instruments – Presentation”. These standards were adopted prospectively.

Capital Disclosures

Effective January 1, 2008, the Trust prospectively adopted Section 1535, “Capital Disclosures” which establishes standards for disclosing information about the Trust’s capital and how it is managed. It requires disclosures of the Trust’s objectives, policies and processes for managing capital, the quantitative data about what the Trust regards as capital, whether the Trust has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The only effect of adopting this standard are disclosures on the Trust’s capital and how it is managed and are included in note 18 to the consolidated financial statements.

Financial Instruments - Disclosures, Financial Instruments – Presentation

Effective January 1, 2008, the Trust prospectively adopted Section 3862, “Financial Instruments Disclosures” and Section 3863, “Financial Instruments Presentations.” These new accounting standards replaced Section 3861, “Financial Instruments – Disclosure and Presentation.” Section 3862 requires additional information regarding the significance of financial instruments for the entity's financial position and performance, and the nature, extent and management of risks arising from financial instruments to which the entity is exposed. The additional disclosures required under these standards are included in note 16 to the consolidated financial statements.

FUTURE ACCOUNTING CHANGES

In February 2008, the CICA issued Section 3064 “Goodwill and Intangible Assets”, replacing Section 3062 “Goodwill and Other Intangible Assets” and Section 3450 “Research and Development Costs”. The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate International Financial Reporting Standards ("IFRS") into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

In January 2009, the CICA issued Section 1582 “Business Combinations”, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the CICA issued Section 1601 “Consolidated Financial Statements” and Section 1602 “Non-controlling Interests”, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

FOURTH QUARTER 2008

The following discussion reviews the Trust’s results of operations for the fourth quarter of 2008.

Production

Light oil and NGL production for the fourth quarter of 2008 decreased by 4% to 7,803 bbl/d from 8,123 bbl/d a year earlier. Heavy oil production for the fourth quarter of 2008 increased by 11% to 24,635 bbl/d from 22,196 bbl/day a year ago due to development drilling in the Seal and Lloydminster area. Natural gas production increased by 7% to 57.6 MMcf/d for the fourth quarter of 2008 as compared to 53.9 MMcf/d for the same period last year primarily due to the acquisition of Burmis in June 2008.

Revenue

Petroleum and natural gas sales decreased 15% to $199.9 million for the fourth quarter of 2008 from $233.9 million for the same period in 2007. Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2008 were 345 bbl/d higher (three months ended December 31, 2007 – 1,717 bbl/d higher) than the production for the period due to changes in inventory.

Revenue from light oil and NGL for the fourth quarter of 2008 decreased 29% from the same period a year ago due to a 4% decrease in sales volume and a 26% decrease in wellhead prices. Revenue from heavy oil decreased 19% as the result of a 23% decrease in wellhead prices slightly offset by a 4% increase in sales volume. Revenue from natural gas increased 19% as the result of a 7% increase in volume and a 12% increase in wellhead prices.

During the current quarter, sulphur production averaged 69.4 tonnes per day with an average price of $131 per tonne. Sulphur revenue for the same period a year ago was not material for reporting purposes.

Royalties

Total royalties decreased to $31.7 million for the fourth quarter of 2008 from $32.5 million in 2007. Royalties for the current quarter include $0.2 million related to the production of sulphur. Total royalties for the fourth quarter of 2008 were 19% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% for the same period in 2007. For the fourth quarter of 2008, royalties were 23% of sales for light oil, NGL and natural gas, and 16% of sales for heavy oil (excluding sales of heavy oil diluent), as compared to 20% and 14%, respectively, for the same period last year. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume increase. Heavy oil royalties increased in 2008 as certain oil sands projects at Seal and Cold Lake reached payout in the third quarter, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the fourth quarter of 2008 increased to $47.4 million from $38.7 million in the corresponding quarter last year. Operating expenses for the current quarter include $0.1 million related to the production of sulphur. Operating expenses were $12.15 per boe for the fourth quarter of 2008 compared to $10.25 per boe for the fourth quarter of 2007. For the fourth quarter of 2008, operating expenses were $12.88 per boe of light oil, NGL and natural gas, and $11.59 per barrel of heavy oil as compared to $9.67 and $10.66, respectively, for the same period in 2007. In the case of light oil, NGL and natural gas, the largest single driver of the increase in unit operating expense was prior-period adjustments to third-party processing costs, which were responsible for a majority of the quarter-over-quarter increase. Other drivers of the increase were increases in labor costs, fuel, power and property taxes. In the case of heavy oil, the increase in quarter-over-quarter operating expense was due primarily to increased fluid hauling charges.

Transportation and Blending Expenses

Transportation and blending expenses for the fourth quarter of 2008 were $45.7 million compared to $43.9 million for the fourth quarter of 2007. Transportation expenses for the current quarter include $0.4 million related to the transportation of sulphur. Transportation expenses were $3.38 per boe for the fourth quarter of 2008 compared to $2.11 for the same period in 2007. Transportation expenses were $0.48 per boe of light oil, NGL and natural gas and $5.24 per barrel of heavy oil in the fourth quarter of 2008, as compared to $0.67 and $3.15, respectively, for the same period of 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and higher fuel costs which, as of the fourth quarter of 2008, had yet to fully respond to the decline in benchmark prices.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of our heavy oil. In the fourth quarter of 2008, the blending cost was $32.5 million for the purchase of 4,820 bbl/d of condensate at $73.34 per barrel, as compared to 4,062 bbl/d at $96.10 per barrel for the same period last year. The cost of diluent is effectively recovered in the sale price of a blended product.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2008 increased to $7.6 million from $6.8 million a year earlier. On a per sales unit basis, these expenses were $1.96 per boe for the fourth quarter of 2008 compared to $1.81 per boe for the same period in 2007. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

Unit-based Compensation Expense

Compensation expense related to our trust unit rights incentive plan was $1.6 million for the fourth quarter of 2008 compared to $1.8 million for the fourth quarter of 2007.

Interest Expense

Interest expense for the fourth quarter of 2008 decreased to $7.9 million compared to $8.6 million in the same quarter last year. The decrease is primarily due to the decrease in prime lending rates and a reduction in the bank loan, partially offset by higher foreign exchange rates on payment of interest on the U.S. dollar denominated debt.

Foreign Exchange

Foreign exchange loss in the fourth quarter of 2008 was $24.8 million compared to a gain of $1.2 million in the fourth quarter of 2007. The 2008 amount is comprised of an unrealized foreign exchange loss of $29.0 million and a realized foreign exchange gain of $4.2 million. The gain in the 2007 period was comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.3 million. The current quarter's unrealized loss is based on the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 0.9435 CAD/USD at September 30, 2008. The prior period gain is based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 1.0037 CAD/USD at September 30, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the fourth quarter of 2008 increased to $61.3 million from $54.1 million for the same quarter in 2007. On a per sales unit basis, the provision for the current quarter was $15.71 per boe compared to $14.33 per boe for the same quarter in 2007. The higher rate is primarily due to the acquisition of Burmis completed in June 2008.

Taxes

Current tax of $1.7 million for the fourth quarter of 2008 is comprised primarily of Saskatchewan capital tax and resource surcharge.

For the fourth quarter of 2008, future tax expense totaled $2.2 million compared to a recovery of $27.7 million in the same period in 2007. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 - $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 - $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 - $153.9 million).

Net Income

Net income for the fourth quarter of 2008 was $52.4 million compared to $41.4 million for the fourth quarter in 2007. The increase was the result of the unrealized gain on financial instruments offset by reduced petroleum and natural gas revenue, higher depletion, foreign exchange losses and future tax expense.

TRUST UNIT INFORMATION

As at February 28, 2009, the Trust had 98,212,328 units outstanding.

As at February 28, 2009, the Trust had $10.4 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

SELECTED ANNUAL INFORMATION

Financial			
($ thousands, except per unit amounts)	**2008**	**2007**	**2006**
Petroleum and natural gas sales	**1,159,718**	745,885	687,016
Net income [(1)]	**259,894**	132,860	147,069
Per unit basic [(1)]	**2.83**	1.66	2.02
Per unit diluted [(1)]	**2.74**	1.60	1.91
Total assets	**1,812,333**	1,407,150	1,079,629
Total long-term financial liabilities	**227,468**	190,004	228,597
Cash distributions declared per unit	**2.64**	2.16	2.16

[(1)] Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2008 was 40,239 boe per day which represented a 11% increase from 36,222 boe per day in 2007. Production in 2006 was 34,292 boe per day. Average wellhead prices net of blending costs received were $65.66 per boe during 2008, $46.53 per boe during 2007 and $44.48 per boe during 2006.

QUARTERLY INFORMATION

	2008					2007				
Production	**TOTAL 2008**	**Q4**	**Q3**	**Q2**	**Q1**	**TOTAL 2007**	**Q4**	**Q3**	**Q2**	**Q1**
Light oil and NGLs (bbl/d)	**7,575**	**7,803**	**8,377**	**6,778**	**7,330**	5,483	8,123	6,556	3,705	3,484
Heavy oil (bbl/d)	**23,530**	**24,635**	**24,078**	**22,905**	**22,484**	22,092	22,196	22,593	21,444	22,129
Total oil and NGLs (bbl/d)	**31,105**	**32,438**	**32,455**	**29,683**	**29,814**	27,575	30,319	29,149	25,149	25,613
Natural gas (MMcf/d)	**54.8**	**57.6**	**60.5**	**51.0**	**50.1**	51.9	53.9	53.7	49.3	50.6
Oil equivalent (boe/d)	**40,239**	**42,035**	**42,538**	**38,179**	**38,157**	36,222	39,304	38,094	33,372	34,041

	2008					2007				
Average Prices	**TOTAL 2008**	**Q4**	**Q3**	**Q2**	**Q1**	**TOTAL 2007**	**Q4**	**Q3**	**Q2**	**Q1**
WTI oil (US$/bbl)	**99.59**	**58.35**	**118.36**	**123.98**	**97.90**	72.31	90.68	75.38	65.03	58.27
Edmonton par oil ($/bbl)	**102.86**	**63.94**	**122.77**	**126.29**	**97.50**	76.35	86.41	80.24	72.15	67.09
BTE light oil ($/bbl)	**88.92**	**55.31**	**107.41**	**109.26**	**84.91**	65.53	74.77	67.82	54.42	51.08
BTE heavy oil ($/bbl)	**65.22**	**38.93**	**84.65**	**78.92**	**59.65**	44.53	50.36	46.18	40.42	40.36
BTE total oil ($/bbl)	**70.94**	**42.83**	**90.56**	**85.82**	**65.66**	48.65	56.55	51.08	42.50	41.82
BTE natural gas ($Mcf)	**7.92**	**7.05**	**8.01**	**9.29**	**7.42**	6.61	6.31	5.80	7.02	7.43
BTE oil equivalent ($/boe)	**65.66**	**42.71**	**80.44**	**79.15**	**61.16**	46.53	52.45	47.23	42.40	42.51

Financial	2008					2007				
($ thousands, except per unit amounts)	**TOTAL 2008**	**Q4**	**Q3**	**Q2**	**Q1**	**TOTAL 2007**	**Q4**	**Q3**	**Q2**	**Q1**
Petroleum and natural gas sales	**1,159,718**	**199,890**	**363,044**	**332,336**	**264,448**	745,885	233,856	193,784	156,670	161,575
Cash distributions declared per unit	**2.64**	**0.68**	**0.75**	**0.65**	**0.56**	2.16	0.54	0.54	0.54	0.54

RECONCILIATION OF NET INCOME TO CASH FLOW FROM OPERATIONS

($ thousands, except per unit amounts)

	2008					2007				
	TOTAL 2008	**Q4**	**Q3**	**Q2**	**Q1**	**TOTAL 2007**	**Q4**	**Q3**	**Q2**	**Q1**
Net income[1]	**259,894**	**52,401**	**137,228**	**34,417**	**35,848**	132,860	41,353	36,674	31,050	23,783
Items not affecting cash:										
Unit-based compensation	**7,812**	**1,563**	**2,038**	**2,129**	**2,082**	7,986	1,810	2,370	1,946	1,860
Unrealized foreign exchange loss (gain)	**41,712**	**29,032**	**7,306**	**(1,636)**	**7,010**	(32,574)	(1,526)	(12,263)	(16,495)	(2,290)
Depletion, depreciation and accretion	**223,900**	**61,251**	**61,250**	**50,941**	**50,458**	189,512	54,086	51,525	42,541	41,360
Accretion on debentures & notes	**1,681**	**519**	**439**	**359**	**364**	2,164	2,059	35	34	36
Unrealized (gain) loss on financial instruments	**(119,917)**	**(86,511)**	**(89,010)**	**48,433**	**7,171**	31,320	27,264	(599)	4,005	650
Future tax expense (recovery)	**15,383**	**2,217**	**25,962**	**(10,318)**	**(2,478)**	(49,369)	(27,659)	(3,895)	(11,307)	(6,508)
Non-controlling interest	**3,358**	**0**	**1,373**	**870**	**1,115**	4,131	1,280	1,110	981	760
Cash flow from operations[2]	**433,823**	**60,472**	**146,586**	**125,195**	**101,570**	286,030	98,667	74,957	52,755	59,651
Change in non-cash working capital	**38,896**	**38,667**	**4,591**	**(24,141)**	**19,779**	5,140	3,145	(308)	956	1,347
Asset retirement expenditures	**(1,443)**	**(725)**	**(351)**	**27**	**(394)**	(2,442)	(1,131)	(351)	(257)	(703)
Decrease in deferred obligations	**(39)**	**(7)**	**(11)**	**(11)**	**(10)**	(2,278)	(550)	(576)	(576)	(576)
Cash flow from operating activities	**471,237**	**98,407**	**150,815**	**101,070**	**120,945**	286,450	100,131	73,722	52,878	59,719
Net income per unit[1]										
Basic	**2.83**	**0.54**	**1.44**	**0.39**	**0.42**	1.66	0.49	0.44	0.41	0.32
Diluted	**2.74**	**0.53**	**1.39**	**0.38**	**0.41**	1.60	0.48	0.43	0.39	0.30
Cash flow from operations per unit[2]										
Basic	**4.73**	**0.62**	**1.53**	**1.42**	**1.19**	3.57	1.17	0.90	0.69	0.79
Diluted	**4.51**	**0.61**	**1.47**	**1.33**	**1.12**	3.54	1.10	0.84	0.65	0.74
Cash flow from operating activities per unit										
Basic	**5.14**	**1.01**	**1.58**	**1.14**	**1.42**	3.58	1.19	0.88	0.69	0.79
Diluted	**4.89**	**0.99**	**1.51**	**1.07**	**1.33**	3.33	1.11	0.83	0.64	0.74

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

(2) The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on GAAP, but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, asset retirement expenditures and decrease in deferred obligations . The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

2009 GUIDANCE

Baytex has set a 2009 exploration and development capital budget of $150 million designed to generate production levels at an annual average of 40,000 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 60 gross wells, including 10 primary horizontal producers in our Seal area in the Peace River oil sands region. The remainder of this budget has been allocated to our conventional oil and gas operations, including the drilling of 18 gross wells. Our 2009 production mix is forecast to be approximately 60% heavy oil, 18% light oil and NGL and 22% natural gas. In addition to the exploration and development capital budget, we expect to incur an additional $10 million for deferred acquisition payments on our North Dakota light oil resource play.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex has entered into the following contracts to provide downside protection to 2009 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – $136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – $172.70	WTI

GAS

	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – CAD 6.30	AECO 7A

Foreign Currency

	Period	Amount	Rate	
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	1.2394 (weighted average)	CAD/USD
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345	

Physical Sale Contracts

HEAVY OIL

	Period	Volume	Price	
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTIx67.0%	(weighted average)
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	80.0%	WTI x
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	US$10.00	WTI less

GAS

	Period	Volume	Price
Price Collar	Calendar 2009	5,000 GJ/d	CAD7.00 - CAD7.95

POWER

	Period	Volume	Price
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$79.92
Fixed	March 1, 2009 to June 30, 2010	0.6 MW/hr	$76.89

Gain or loss on financial derivative contracts comprise realized and unrealized gains or losses on financial instruments that do not meet the accounting definition requirements of an effective hedge, even though the Trust considers all financial derivative contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate category in the statement of income.

Strong commodity prices throughout most of 2008 had a significant impact on the Trust's revenue; however, these strong prices resulted in realized cash losses of $51.4 million for the Trust's oil and natural gas financial derivative contracts. During 2008, the Trust recorded a $8.7 million realized loss on foreign exchange financial derivative contracts due to the strengthening of the U.S. dollar during the year.

The 2008 results of the Trust include an unrealized mark-to-market gain of $119.9 million with a net unrealized mark-to-market asset gain position of $85.7 million. The mark-to-market values represent the market price to buy-out the Trust's contracts as of December 31, 2008 and may be different from what will eventually be realized.

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 16 to the consolidated financial statements for a more detailed description of accounting treatment of these derivative contracts.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Baytex.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

The Federal Government and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our operations and financial condition.

Further information regarding environmental regulation is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

The New Royalty Framework

On October 25, 2007, the Alberta government announced the "New Royalty Framework" ("NRF"), which introduced the following changes to Alberta's royalty regime effective January 1, 2009:

- Conventional oil – overall royalty rates increased from the pre-NRF maximum of 30% and 35% for old and new tiers. The NRF rates vary on a sliding scale basis up to 50%, and rate caps have been raised to $120 per barrel for West Texas Intermediate crude.

- Natural gas – the Government eliminated "old" and "new" tiers. Royalty rates, pre-NRF at 5% to 35% increased to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at $16.59/GJ.

- Oil Sands – before NRF, the pre-payout royalty rate was 1%. Under the NRF, this rate increased for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the previous regime, once an oil sands project reached payout, the 1% royalty converted to a 25% net profits interest. Under the NRF, the net profits interest applies at the rate of 25% when oil is less than $55 per bbl of WTI, and increases for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

On November 19, 2008, the Alberta Government announced transitional amendments to the NRF for certain types of drilling. In general terms, operators will have a one-time option of selecting either the transitional royalty regime or the NRF when drilling a new natural gas or conventional oil well 1,000 to 3,500 metres in depth. The transitional regime effectively caps royalty rates at 30% for those wells which qualify, and reduces the commodity prices and production rates at which the top 50% royalty rate kicks in for oil wells. All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the NRF on January 1, 2014. The transitional regime is not applicable to oil sands projects or to wells producing before January 1, 2009.

On March 3, 2009, the Alberta Government announced a new well incentive program intended to stimulate conventional drilling activity. The incentive program offers a one-year royalty credit for conventional oil and gas wells of $200 per metre drilled with the maximum benefit of the incentive accruing to smaller companies. The program also provides for a maximum 5% royalty for all new wells that begin producing conventional oil and gas between April 1, 2009 and March 31, 2010.

Further information regarding NRF is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the SIFT tax rate to 28% as compared to the rate of 31.5% previously announced subject to comments below concerning the provincial SIFT tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law amendments to the Income Tax Act (Canada) that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "SIFT"), such as Baytex, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "SIFT Rules"). Subject to the Provincial SIFT Tax Proposal described below, the SIFT Rules currently provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined tax rate of 29.5% in 2011 and 28% in 2012.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a specified investment flow-through trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount carrying forward to the next year. We did not issue equity in excess of the safe harbour limits during 2006/2007 or 2008. As at December 31, 2008, we had unused safe harbour limit of $596.6 million that was carried forward, resulting in a safe harbour limit of $961.6 million for 2009.

On December 20, 2007, the Minister of Finance announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement, the Minister of Finance indicated that the Federal Government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequence to investors or the trusts.

On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada; and

- that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, we would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011 and 25% in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

In 2008, the Federal Government also introduced draft tax legislation to facilitate the conversion of existing income trusts into corporations on a tax deferred basis and to accelerate the recognition of the "safe harbor" limit. Neither this draft tax legislation nor the Provincial SIFT Tax Proposal was enacted prior to prorogation of parliament in December 31, 2008. Therefore, all bills containing the draft legislation had lapsed as of that date.

Subsequent to the year end, the Federal Government introduced draft tax legislation which included the above mentioned measures as part of Canada's Economic Action Plan. This legislation received Royal assent on March 12, 2009, and was therefore was passed into law. We continue to review the impact of the future taxation of distributions on our business strategy but at this time have made no decision as to the ultimate legal form under which we will operate post 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

Disclosure Controls and Procedures

As of December 31, 2008, an internal evaluation was conducted of the effectiveness of the Trust's “disclosure controls and procedures” (as defined in the United States by Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”)). Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Trust’s disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein and accumulated and communicated to the Trust's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Trust’s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Trust’s disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

“Internal control over financial reporting” (as defined in the United states by Rule 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Management has assessed the effectiveness of the Trust's internal control over financial reporting. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche LLP, as reflected in their report for 2008.

No changes were made to our internal control over financial reporting during the year ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: our ability to maintain production levels by investing approximately half of our internally generated cash flow; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; development plans for our properties; our heavy oil resource play at Seal, including our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, operating costs and the resource potential of our undeveloped land; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates and average recoveries per well; oil and gas prices and differentials between light, medium and heavy oil prices; the demand for and supply of crude oil and natural gas; the level of natural gas drilling activity in North America; the sufficiency of our capital resources to meet our ongoing short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the extension of our credit facilities upon maturity; funding sources for our cash distributions and capital program; the timing of funding our financial obligations; the impact of the adoption of new accounting standards on our financial results; our production levels for 2009, including our product mix; our exploration and development capital program for 2009; the timing and allocation of our exploration and development expenditures; the timing and amount of deferred acquisition payments for the North Dakota acquisition; the impact of new environmental regulation; potential changes to our business form; and the taxation of income trusts. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2008, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Exhibit 99.4

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, Anthony W. Marino, certify that:

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

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 period 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.

Dated: March 26, 2009

(signed) "*Anthony W. Marino*"
Name: Anthony W. Marino
Title: President and Chief Executive Officer, Baytex Energy Ltd.

Exhibit 99.5

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, W. Derek Aylesworth, certify that:

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

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)) 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.

Dated: March 26, 2009

(signed) "*W. Derek Aylesworth*"
Name: W. Derek Aylesworth, CA
Title: Chief Financial Officer, Baytex Energy Ltd.

Exhibit 99.6

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 Baytex Energy Trust (the "Company") on Form 40-F for the fiscal year ended December 31, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Anthony W. Marino, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

Dated: March 26, 2009

(signed) "*Anthony W. Marino*"
Name: Anthony W. Marino
Title: President and Chief Executive Officer, Baytex Energy Ltd.

Exhibit 99.7

ERTIFICATION 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 Baytex Energy Trust (the "Company") on Form 40-F for the fiscal year ended December 31, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Derek Aylesworth, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

Dated: March 26, 2009

(signed) "*W. Derek Aylesworth*"
Name: W. Derek Aylesworth, CA
Title: Chief Financial Officer

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

We consent to the use of our reports dated March 16, 2009 relating to the consolidated financial statements of Baytex Energy Trust (which report expresses an unqualified opinion and includes a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference relating to changes in accounting principles) and the effectiveness of Baytex Energy Trust's internal control over financial reporting appearing in this Annual Report on Form 40-F of Baytex Energy Trust for the year ended December 31, 2008.

(signed) "*Deloitte & Touche LLP*"
Independent Registered Chartered Accountants
Calgary, Canada
March 16, 2009

Exhibit 99.9

Ref.: 2077.16239

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated March 4, 2009 and effective December 31, 2008, evaluating the oil, natural gas and natural gas liquids reserves attributable to Baytex Energy Trust and its subsidiaries, entitled “Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2008)”, (the “Report”).

We hereby consent to the references to our name in the Company’s Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

We also confirm that we have read the Company’s Annual Information Form for the year ended December 31, 2008 dated March 26, 2009, and that we have no reason to believe that there are any misrepresentations in the information contained therein 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.

SPROULE ASSOCIATES LIMITED

(signed) *"R. Keith Macleod"*
R. Keith MacLeod, P. Eng.
Executive Vice-President

Calgary, Alberta, Canada
March 26, 2009