U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(CHECK ONE)

o **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

or

ý **Annual Report pursuant to Section 13(1) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: December 31, 2003

Commission File Number: 333-07612

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:**
NONE	

Securities registered pursuant to Section 12(g) of the Act:
TRUST UNITS

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:
ý Annual Information Form ý 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.
Trust Units: 60,821,277

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 o No ý

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 ý No o

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

Baytex Energy Trust (the "Registrant") conducts its principal business through an operating subsidiary, Baytex Energy Ltd. (the "Company").

Principal Documents

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, 2003, see Exhibit 1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the consolidated audited financial statements for the year ended December 31, 2003, including the report of independent chartered accountants with respect thereto, see Exhibit 2 of this Annual Report on Form 40-F. For a reconciliation of differences between Canadian and United States generally accepted accounting principles, see Note 17 of the Notes to the Consolidated Financial Statements.

C. Management's Discussion and Analysis

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

Controls and Procedures

A. Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of the end of the period covered by this Annual Report on Form 40-F (the "evaluation date"), that the Registrant's and the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

B. *Changes in Internal Control Over Financial Reporting*

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

Code of Ethics

The Company's code of ethics, which is applicable to its principal executive officer and senior financial officers, is posted on its website at www.baytex.ab.ca. In the event that the Company:

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

(ii) grants a waiver, including an implicit waiver, from a provision of its Code of Ethics to any of the Company's principal executive officer, principal financial officer, principal accounting officer, or controller or persons performing similar functions that relates to any element of the code of ethics definition as enumerated in paragraph (9)(b) of General Instruction B to Form 40-F,

the Company will disclose on its website any amendment to, or waiver of, a provision of its Code of Ethics within five business days following the date of any such amendment or waiver, and will, in the case of a waiver, name the persons to whom the waiver was granted.

Principal Accountant Fees and Services

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

	Aggregate fees billed by the Principal Accountant	
	2003	2002
	($thousands)	
Audit fees	154	92
Audit-related fees	277	67
Tax fees	273	112
All other fees	NIL	NIL
	704	271

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

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

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

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

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

Off-Balance Sheet Arrangements and 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, 2003, which is filed as Exhibit 3 to this Annual Report on Form 40-F.

UNDERTAKING

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, 2002.

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

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 annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Registrant: BAYTEX ENERGY TRUST

By: Baytex Energy Ltd.

By: /s/ Daniel G. Belot
Name: Daniel G. Belot
Title: Vice-President Finance and Chief Financial Officer

Date: May 19, 2004

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Exhibit No.	Document
1.	Annual Information Form of the Registrant for the fiscal year ended December 31, 2003
2.	Comparative audited Financial Statements of the Registrant for the year ended December 31, 2003, including reconciliation to United States generally accepted accounting principles, together with the Auditors' Report thereon.
3.	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2003.
4.	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
5.	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
6.	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
7.	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
8.	Consent of Deloitte & Touche, LLP, independent accountants.
9.	Consent of Sproule Associates Limited., independent engineers.

Exhibit 1

BAYTEX ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

2003

May 10, 2004

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GLOSSARY OF TERMS

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**Administration Agreement**" means the amended and restated administration agreement dated November 12, 2003, between Baytex and the Trustee, on behalf of the Trust;

"**ARTC**" means credits or rebates in respect of Crown royalties which are paid or credited by the Crown, including those paid or credited under the Alberta Corporate Tax Act which are commonly known as "Alberta ARTC Credits";

"**Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among Baytex, Crew, Baytex Acquisition Corp., Baytex ExchangeCo Ltd., Baytex Resources Ltd., Baytex Exploration Ltd. and the Trust which was completed on September 2, 2003 and 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 the Trust;

"**Baytex**" or the "**Corporation**" means Baytex Energy Ltd., a corporation amalgamated under the ABCA;

"**Business Day**" means a day, which is not a Saturday, Sunday or statutory holiday, when banks in the place at which any action is required to be taken hereunder are generally open for the transaction of commercial banking business;

"**Capital Fund**" means the cash flow retained by the Trust from cash otherwise available for distribution which shall be advanced to the

Corporation, as the case may be, to finance development of the Properties and future acquisitions;

"**Crew**" means Crew Energy Inc., a corporation incorporated under the ABCA;

"**Deferred Purchase Obligation**" means, collectively, the ongoing obligation of the Trust to pay to Baytex, to the extent of the Trust's available funds, an amount equal to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by Baytex, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties;

"**Direct Royalties**" mean royalty interests in petroleum and natural gas rights acquired by the Trust from time to time;

"**Exchangeable Shares**" means the exchangeable shares in the capital of Baytex;

"**ExchangeCo**" means Baytex ExchangeCo Ltd., a corporation incorporated under the ABCA;

"**Exchange Ratio**" means at any time and in respect of each Exchangeable Share, which was initially equal to 1.00000 as at the effective date of the Arrangement and which has been and is cumulatively adjusted by: (a) increasing the Exchange Ratio on each distribution payment date on the time as of which the Exchange Ratio is calculated by an amount, rounded to the nearest five decimal places, equal to a fraction having as its numerator the distribution, expressed as an amount per Trust Unit, paid on that distribution payment date, multiplied by the Exchange Ratio immediately prior to the distribution record date for such distribution and having as its denominator the current market price of a Trust Unit on the first Business Day following the distribution record date for such distribution; and (b) decreasing the Exchange Ratio on each dividend record date between the Effective Date and the time as of which the Exchange Ratio is calculated by an amount, rounded to the nearest five decimal places, equal to a fraction having as its numerator the dividend declared on that dividend record date, expressed as an amount per Exchangeable Share multiplied by the Exchange Ratio immediately prior to that dividend record date, and having as its denominator the Current Market Price of a Trust Unit;

"**Insolvency Event**" means the institution by Baytex of any proceeding to be adjudicated to be a bankrupt or insolvent or to be wound up, or the consent of Baytex to the institution of bankruptcy, dissolution, insolvency or winding-up proceedings against it, or the filing of a petition, answer or consent seeking dissolution or winding-up under any bankruptcy, insolvency or analogous laws, including without limitation the *Companies Creditors' Arrangement Act* (Canada) and the *Bankruptcy and Insolvency Act* (Canada), and the failure by Baytex to contest in good faith any such proceedings commenced in respect of Baytex within 15 days

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of becoming aware thereof, or the consent by Baytex to the filing of any such petition or to the appointment of a receiver, or the making by Baytex of a general assignment for the benefit of creditors, or the admission in writing by Baytex of its inability to pay its debts generally as they become due, or Baytex not being permitted, pursuant to solvency requirements of applicable law, to redeem any retracted Exchangeable Shares pursuant to the Exchangeable Share provisions;

"**Liquidation Amount**" means the amount that holders of Exchangeable Shares are entitled to in the event of the liquidation, dissolution or winding-up of Baytex or any other distribution of the assets of Baytex among its shareholders for the purpose of winding up its affairs;

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**Non-Residents**" means non-residents of Canada within the meaning of the Tax Act;

"**Note Indenture**" means the note indenture dated as of September 2, 2003 among Valiant Trust Company and Baytex providing for the issuance of the Notes;

"**Notes**" means the 12% unsecured subordinated promissory notes of Baytex originally issued on September 2, 2003;

"**NP 2-B**" means National Policy 2-B of the Canadian Securities Administrators ;

"**NPI**" means the 99% interest in Baytex's Petroleum Substances within, upon or under certain of its Oil and Natural Gas Properties granted pursuant to the NPI Agreement;

"**NPI Agreement**" means the net profit interest agreement entered into between Baytex and the Trust dated as of September 2, 2003 and providing for the creation of the NPI;

"**OGY**" means OGY Petroleums Ltd.;

"**Oil and Natural Gas Properties**" or "**Properties**" means the working, royalty or other interests of the Corporation from time to time in any petroleum and natural gas rights, tangibles and miscellaneous interests, and including the Direct Royalties acquired by the Trust from time to time;

"**Ordinary Resolution**" means a resolution approved at a meeting of Unitholders and the holder of the Special Voting Right by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders and the holder of the Special Voting Right present in person or represented by proxy at the meeting;

"**Permitted Investments**" means: (a) loan advances to or from Baytex including loans made in connection with the Capital Fund; (b) interest bearing accounts of certain financial institutions, including Canadian chartered banks and the Trustee; (c) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof; (d) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee), the short term debt or deposits of which have been rated at least A by Standard & Poor's Corporation, or the equivalent by Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited; (e) commercial paper rated at least A by Standard &

Poor's Corporation, or the equivalent by Canadian Bond Rating Service Inc. or Dominion Bond Rating Service Limited; and (f) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business, including securities of the Corporation;

"**Petroleum Substances**" means petroleum, natural gas and related hydrocarbons (including condensate and natural gas liquids), and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbon or not, produced in association therewith;

"**Pro Rata Share**" of any particular amount in respect of a Unitholder at any time shall be the amount obtained by dividing the number of Trust Units that are owned by that Unitholder at that time by the total number of all Trust Units that are issued and outstanding at that time;

"**Proved Reserves**", "**Probable Reserves**", "**Proved Producing Reserves**", "**Proved Undeveloped Reserves", Proved Non-Producing Reserves**" and "**Total Proved Reserves**" have the meanings given to those terms in the Sproule Report;

"**Redemption Notes**" means notes issued in certain circumstances including by the Trust on a redemption of Trust Units;

"**Special Resolution**" means a resolution proposed to be passed a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 5% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and polled and voted on a poll upon such resolution. For the purposes of determining such percentage, the holder of any Special Voting Right who is present at the meeting shall be regarded as representing outstanding Units equivalent in number to the votes attaching to such Special Voting Right;

"**Special Voting Right**" means the Special Voting Right of the Trust, issued and certified under the Trust Indenture for the time being outstanding and entitled to the benefits and subject to the limitations set forth therein;

"**Special Voting Unit**" means special voting units which may be issued by the Trust from time to time entitling the holders thereof to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors of the Corporation in the resolution authorizing the issuance of any such Special Voting Units;

"**Sproule"** means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta;

"Sproule Report" means the report dated March 23, 2004 entitled "Evaluation of the P&NG Reserves of Baytex Energy Trust as of January 1, 2004".

"**Subsequent Investment**" includes (a) investing in securities of Baytex, ExchangeCo or any other subsidiary of the Trust, which investments shall be for the purpose of funding the acquisition, development, exploitation and disposition of all types of petroleum and natural gas and energy related assets, including without limitation, facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets (hereinafter referred to as "Energy Assets") and whether effected by Baytex or any other subsidiary of the Trust through an acquisition of assets or an acquisition of shares or other form of ownership interest in any entity the substantial majority of the assets of which are comprised of like assets; (b) acquiring or investing in the securities of any other entity, including without limitation bodies corporate, partnerships or trusts, and borrowing funds or otherwise obtaining credit, including the granting guarantees, for that purpose, for the purpose of directly or indirectly acquiring Energy Assets; (c) acquiring Direct Royalties; (d) making loans or other advances to Baytex in connection with the Capital Fund; and (d) acquiring royalties in respect of Canadian resource properties as defined in the Tax Act and making any deferred royalty purchase payments which may be required with respect to such royalties; provided however that in no event shall the Trust invest in any royalties which constitute an interest in land or a covenant running with the Properties with respect to which such royalties relate;

"**Support Agreement**" means the support agreement entered into on September 2, 2003 between the Trust, Baytex, ExchangeCo and Valiant Trust Company;

"**Tax Act**" means the *Income Tax Act* (Canada), as amended;

"**Triumph**" means Triumph Energy Corporation;

"**Trust Indenture**" means the amended and restated trust indenture between the Trustee and Baytex made as of September 2, 2003;

"**Trust**" means Baytex Energy Trust, a trust established under the laws of Alberta pursuant to the Trust Indenture. All references to the "Trust", unless the context otherwise requires, are references to Baytex Energy Trust, its predecessors, and its subsidiaries;

"**Trust Unit**" or "**Unit**" means a unit of the Trust, each unit representing an equal undivided beneficial interest therein;

"**Trust Unit Rights Incentive Plan**" means the trust unit rights incentive plan of the Trust;

"**Trustee**" means Valiant Trust Company, or such other trustee, from time to time, of the Trust;

"**TSX**" means the Toronto Stock Exchange;

"**United States**" or "**U.S.**" means the United States of America;

"**Unitholders**" or "**Trust Unitholders**" means the holders from time to time of the Trust Units;

"**Voting and Exchange Trust Agreement**" means the voting and exchange trust agreement entered into on September 2, 2003 between the Trust, Baytex, ExchangeCo and Valiant Trust Company;

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbls	barrels
Mbbls	thousand barrels
Mmbbls	million barrels
NGLs	natural gas liquids
Stb	stock tank barrels of oil
Mstb	thousand stock tank barrels of oil
Bbls/d	barrels per day

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet 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.
Psi	means pounds per square inch.

CONVERSION

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
bbls	cubic metres	0.159
cubic metres	bbls	6.289
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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Trust's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect",

"may", "will", "project", "predict", "potential", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and Baytex believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of the oil and natural gas assets of the Trust;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes;
- capital expenditure programs;
- the existence, operation and strategy of the Trust's commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed by the Trust;
- the Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- the impact of Canadian federal and provincial governmental regulation on the Trust relative to other oil and gas issuers of similar size;
- the goal to grow or sustain production and reserves through prudent management and acquisitions;
- the emergence of a creed of growth opportunities; and
- the Trust's ability to benefit from the combination of growth opportunities and the ability to grow through capital markets.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form:

- volatility 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;
- geological, technical, drilling and processing problems; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on current estimates and assumptions that the resources and reserves described can be profitably produced in the future. The foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement.

Neither the Trust nor Baytex undertakes any obligation to publicly update or revise any forward-looking statements. See "*Management's Discussion and Analysis*".

BAYTEX ENERGY TRUST

General

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

The Trust was formed on July 24, 2003 and commenced operations on September 2, 2003 as a result of the completion of the Arrangement. Pursuant to the 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 the Trust. See "*General Development of the Business*".

Inter-Corporate Relationships

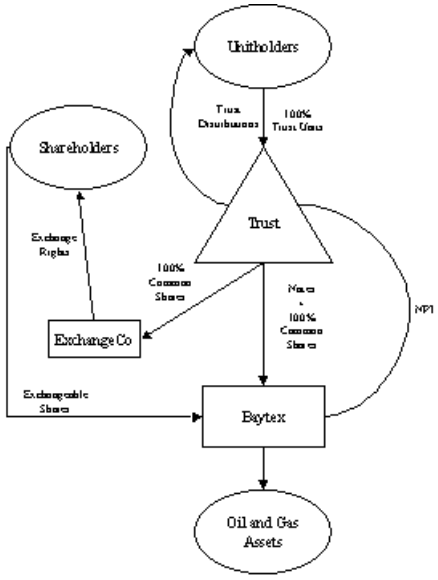
The following table provides the name, the percentage of voting securities owned by the Trust and the jurisdiction of incorporation, continuance or formation of the Trust's subsidiaries either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Baytex Energy Ltd.	100%	Alberta
Baytex ExchangeCo Ltd.	100%	Alberta

Baytex Marketing Ltd.	100%	Alberta

Organizational Structure of the Trust

The following diagram describes the inter-corporate relationships among the Trust and its material subsidiaries as well as the flow of cash from the Oil and Natural Gas Properties held by such subsidiaries to the Trust, and from the Trust to the Unitholders.



Notes:

(1) The Unitholders own 100% of the equity of the Trust.
(2) Baytex had a total of 3,724,649 Exchangeable Shares issued and outstanding as at December 31, 2003.
(3) Cash distributions are made on a monthly basis to Unitholders based upon the Trust's cash flow. The Trust's primary sources of cash flow are payments from Baytex pursuant to the NPI and interest on the principal amount of the Notes. In addition to such amounts, prepayments in respect of principal on the Notes may be made from time to time by Baytex to the Trust before the maturity of the Notes.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

In May 2001, Baytex acquired all of the issued and outstanding shares of OGY, a public oil and gas company, the shares of which were listed on the TSX. The total consideration paid by Baytex for OGY was $50.7 million in cash and 1.2 million Baytex common shares. The operations of OGY concentrated on light oil and natural gas in central Alberta.

Also in May 2001, Baytex acquired all of the issued and outstanding shares of Triumph, a public oil and gas company, the shares of which were listed on the TSX. The total consideration paid for Triumph was $82.3 million in cash and 4.9 million Baytex common shares. The operations of Triumph were focused on the exploration and development of natural gas in Central Alberta and light oil and natural gas in East Central and Southern Alberta.

Additional heavy oil assets were acquired in the Cold Lake, Alberta and Carruthers, Saskatchewan areas in three separate property acquisitions in 2001 and 2002 for total cash consideration of $73.4 million.

In the fourth quarter of 2001 and first quarter of 2002, Baytex executed a plan to strengthen its balance sheet with the divestiture of certain oil and natural gas assets. This plan included the sale of light oil and natural gas assets for total proceeds of $101 million. This was later augmented in the first quarter of 2003 with the completion of the sale of natural gas assets in the Ferrier/O'Chiese area for proceeds of $133.3 million. Proceeds of the asset sales were applied to reduce outstanding indebtedness.

In October 2002, Baytex signed a five-year crude oil supply agreement with a U.S. based refining company. This agreement calls for the delivery, beginning in January 2003, of up to 20,000 Bbls/d of Lloyd Blend oil production at a fixed differential of 29 percent of West Texas Intermediate price. This pricing arrangement effectively removes the additional pricing volatility associated with heavy oil on two-thirds of Baytex's heavy oil production. This contract forms part of Baytex's risk management program and should help to reduce the impact on Baytex's cash flow from dramatic swings in commodity prices in the future.

On September 2, 2003, Baytex completed the Arrangement whereby holders of common shares of Baytex elected or were deemed to have elected to receive either Trust Units or Exchangeable Shares of Baytex for their common shares on the basis of one Trust Unit or Exchangeable

Share, respectively, for each common share held. Coincident with the 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. The estimated fair market value at September 2, 2003 of the securities issued during the reorganization was $11.76 per Trust Unit and $0.55 per one-third of a common share of Crew.

On December 12, 2003 the Trust 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 this offering were used to fund the Trust's ongoing capital expenditure and acquisition program. The Trust's 2004 capital expenditure budget has been set between $100 and $110 million and is primarily directed toward development of the Trust's existing Properties.

Trends

There are a number of trends in the oil and gas industry that are shaping the near term future of the business. One trend has been the continuation of oil and gas companies converting to royalty trusts. These conversions occur because the equity markets generally value trusts at higher multiples than exploration and development firms. The conversion announcement often results in the appreciation of its share price to premiums equivalent to other trusts. Including recent conversions, approximately half of the top 30 publicly listed oil and gas issuers on the TSX are now trusts.

Efforts of trusts to replace annual production declines have resulted in continued 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 economically replace production through internal development drilling should be in a favourable position relative to those more exposed to replacing production through acquisitions.

Another trend is the continuing volatility of commodity prices. World oil inventories experienced a significant drawdown in 2003 and the rate of recovery will largely be dependent on weather, Iraq's export recovery, middle-eastern conflict, and OPEC's discipline. As long as inventories remain low, the high crude oil prices the industry experienced over the past year could continue. Natural gas inventories are at more normal levels; however, natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America. As weather is a key factor in determining gas demand, future gas prices are highly unpredictable.

Although commodity prices are higher than historical levels, the appreciation of the Canadian dollar in 2003 relative to its US counterpart has offset a portion of the economic benefit of higher prices on Canadian oil and gas producers including trusts. The stronger Canadian dollar may result in decreased revenues in 2004 for oil and gas producers on a per barrel basis increasing pressure on the royalty trusts' ability to maintain current distribution levels.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Baytex Energy Trust

The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture. The Trust was established to, among other things:

- invest in shares of Baytex and acquire the common shares of Baytex and the Notes pursuant to the Arrangement;
- 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, and borrowing funds or otherwise obtaining credit for that purpose;
- 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 as contemplated by 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.

The Trust is prohibited from acquiring any investment which (a) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by section 5000 of the Tax Regulations or (b) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

The principal undertaking of the Trust is to issue Trust Units and to acquire and hold royalties and other interests. The direct and indirect subsidiaries of the Trust carry on the business of acquiring and holding interests in Oil and Natural Gas Properties and assets related thereto. Cash flow from the Properties is flowed from Baytex to the Trust by way of interest payments and principal repayments on the Notes and payments from Baytex to the Trust under the NPI Agreement.

The Trustee may declare payable to the Unitholders all or any part of the income of the Trust. It is currently anticipated that the only income to be received by the Trust will be from the interest and principal payments received on the principal amount of Notes and payments pursuant to the NPI Agreement. The Trust makes monthly cash distributions to Unitholders of the interest income earned from the Notes and income earned under the NPI Agreement, 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.

The current distribution policy allows the use of between 30% and 40% of cash available for capital expenditures which will fund both exploration and development expenditures and minor property acquisitions, but excluding major acquisitions. Baytex's senior subordinated notes also contain certain limitations on maximum cumulative distributions.

Baytex Energy Ltd.

Baytex is actively engaged in the business of oil and gas exploration, development, acquisition and production in the provinces of Alberta and Saskatchewan.

Baytex employs a strategy to maintain production from Baytex's existing production base while focusing capital expenditures on low-risk development opportunities. Baytex utilizes financial derivative contracts, when deemed appropriate, to manage and reduce the volatility in commodity prices. See "*Risk Factors*". Baytex generally sells or farms out higher risk projects while actively pursuing growth opportunities through oil and gas property acquisitions, as well as through corporate acquisitions. Baytex targets acquisitions that are accretive to net asset value and that increase the Trust's reserve and production base per Trust Unit outstanding. Acquisitions must also meet reserve life index criteria and exhibit low risk opportunities to increase reserves and production. It is currently intended that Baytex will finance acquisitions and investments through cash flow not distributed to Unitholders, debt financing and the issuance of additional Trust Units from treasury in order to maintain prudent leverage.

Baytex was incorporated under the ABCA on June 3, 1993. On August 5, 1993, Baytex filed Articles of Amendment to delete the private company restrictions thereunder. On October 13, 1993, Articles of Amendment were filed to amend Baytex's capital structure to create Class A Shares and Class B Non-Voting Shares. On October 21, 1997, Baytex filed Articles of Amalgamation to amalgamate with its wholly-owned subsidiary, Dorset Exploration Ltd. On May 28, 1999, Baytex filed Articles of Amendment to eliminate the Class B Shares and to change the designation of the Class A Shares in the share capital of Baytex from "Class A Shares" to "common shares". On January 1, 2002, Baytex filed Articles of Amalgamation to amalgamate with its wholly-owned subsidiaries, OGY and Triumph. On September 2, 2003, Baytex was amalgamated with Baytex Acquisition Corp. pursuant to the Arrangement. Baytex is actively engaged in the business of oil and natural gas exploration, development, acquisition and production in Canada.

The Trust is the sole common shareholder of Baytex. Certain former shareholders of Baytex own Exchangeable Shares in accordance with the elections made by such shareholders under the Arrangement. Baytex continues to carry on an oil and natural gas business similar to that carried on by Baytex prior to the Arrangement becoming effective. Baytex owns, directly or indirectly, all of the assets that were owned by Baytex prior to the Arrangement becoming effective, other than certain exploration assets that were transferred to Crew in accordance with the Arrangement.

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

Disclosure of Reserves Data and Other Oil and Gas Information

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated January 1, 2004. The effective date of the Statement is January 1, 2004 and the preparation date of the Statement is March 23, 2004. 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.

The reserves data set forth below (the "Reserves Data") is based upon the Sproule Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Trust and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. The Trust engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Trust's reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material.

NI 51-101 replaces the former National Policy 2-B ("NP 2-B") and requires a higher degree of confidence in the assignment of oil and gas reserves. Under NI 51-101, proved reserves are defined to have a 90% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "reasonable certainty" as stipulated by NP 2-B. Also, under NI 51-101, probable reserves are defined to have a 50% probability that the actual reserves recovered will equal or exceed the assigned estimates compared to the previous definition of "likelihood of existence" in NP 2-B. Because of the more stringent requirements under NI 51-101, the industry has adopted the interpretation that the new proved plus probable (P-50) reserves represent the most "realistic" estimates of remaining recoverable reserves. The following reserves information also adopts the general industry practice of comparing the new P-50 reserves to the previous proved plus risk adjusted (50%) probable reserves, commonly referred to as "established reserves", under NP 2-B.

The Trust is classified as a unit trust for income tax purposes, and is taxable on income not distributed to public Unitholders. The Trust has and expects to allocate all of its taxable income to Unitholders. Accordingly, no provision for income taxes is required at the Trust level and all information for the most recent oil and gas reserves has been presented on a pre-tax basis only.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF JANUARY 1, 2004
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Bcf)	Net (Bcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	3,974.6	3,673.7	24,692.6	22,379.8	74.2	60.1	248.5	174.4	41,278	36,244
Developed Non-Producing	143.9	126.4	15,212.9	13,034.4	3.8	3.0	8.5	5.7	15,999	13,671
Undeveloped	1,292.7	1,126.6	17,650.0	16,119.1	4.1	3.2	4.3	2.9	19,632	17,780
TOTAL PROVED	5,411.2	4,926.7	57,555.5	51,533.3	82.1	66.3	261.3	183.0	76,908	67,694
PROBABLE	1,730.5	1,556.0	23,641.2	21,440.4	25.1	20.4	94.9	64.5	29,646	26,454
TOTAL PROVED PLUS PROBABLE	7,141.7	6,482.7	81,196.7	72,973.7	107.2	86.7	356.2	247.5	106,554	94,149

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT	
	0% ($ Million)	10% ($ Million)
PROVED		
Developed Producing	691.5	547.3
Developed Non-Producing	194.9	128.5
Undeveloped	186.7	117.9
TOTAL PROVED	1,073.1	793.7
PROBABLE	394.7	229.9
TOTAL PROVED PLUS PROBABLE	1,467.8	1,023.5

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF JANUARY 1, 2004
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($ Million)	ROYALTIES ($ Million)	OPERATING COSTS ($ Million)	DEVELOPMENT COSTS ($ Million)	WELL ABANDONMENT COSTS ($ Million)	FUTURE NET REVENUE BEFORE INCOME TAXES ($ Million)
Proved Reserves	2,052.8	261.9	572.2	133.1	12.5	1,073.1
Proved Plus Probable Reserves	2,821.3	350.4	784.6	200.1	18.4	1,467.8

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF JANUARY 1, 2004
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($ Million)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	62.3
	Heavy Oil (including solution gas and other by-products)	513.3
	Natural Gas (including by-products but excluding solution gas from oil wells)	218.1
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	77.2
	Heavy Oil (including solution gas and other by-products)	680.6
	Natural Gas (including by-products but excluding solution gas from oil wells)	265.7

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF JANUARY 1, 2004
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Bcf)	Net (Bcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	3,722.0	3,445.2	24,664.0	22,441.7	73.3	59.4	247.7	174.4	40,825	35,955
Developed Non-Producing	143.9	127.4	15,203.9	13,118.7	3.8	3.0	8.5	5.8	15,989	13,757
Undeveloped	1,292.7	1,140.9	17,719.6	16,323.7	4.1	3.2	4.3	2.9	19,697	17,996
TOTAL PROVED	5,158.6	4,713.5	57,567.5	51,884.1	81.2	65.6	260.5	183.1	76,510	67,708
PROBABLE	1,649.0	1,493.0	23,606.1	21,556.8	24.6	20.0	94.8	64.8	29,457	26,447
TOTAL PROVED PLUS PROBABLE	6,807.6	6,206.5	81,173.6	73,440.9	105.8	85.6	355.3	247.9	105,967	94,154

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT				
RESERVES CATEGORY	0% ($ Million)	5% ($ Million)	10% ($ Million)	15% ($ Million)	20% ($ Million)
PROVED					
Developed Producing	521.4	472.5	427.9	391.9	362.9
Developed Non-Producing	135.6	107.7	88.4	74.3	63.7
Undeveloped	108.0	80.9	61.0	46.1	34.6
TOTAL PROVED	765.0	661.1	577.3	512.3	461.2
PROBABLE	276.7	203.2	156.1	123.8	100.5
TOTAL PROVED PLUS PROBABLE	1,041.7	864.3	733.4	636.1	561.7

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF JANUARY 1, 2004
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($ Million)	ROYALTIES ($ Million)	OPERATING COSTS ($ Million)	DEVELOPMENT COSTS ($ Million)	WELL ABANDONMENT COSTS ($ Million)	FUTURE NET REVENUE BEFORE INCOME TAXES ($ Million)
Proved Reserves	1,729.9	214.4	603.1	134.9	12.5	765.0
Proved Plus Probable Reserves	2,382.5	285.5	833.3	203.7	18.3	1,041.7

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF JANUARY 1, 2004
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($ Million)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	41.3
	Heavy Oil (including solution gas and other by-products)	354.9
	Natural Gas (including by-products but excluding solution gas from oil wells)	181.1
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	52.5
	Heavy Oil (including solution gas and other by-products)	460.9
	Natural Gas (including by-products but excluding solution gas from oil wells)	219.9

Definitions and Other Notes

In the tables set forth above in "*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 the Trust's interest in production and reserves, its interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Trust;

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

   (c) in relation to Properties, the total area of Properties in which the Trust has an interest.

2. "Net" means:

   (a) in relation to the Trust's interest in production and reserves, its interest (operating and non-operating) share after deduction of royalties obligations, plus the Trust's royalty interest in production or reserves.

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

   (c) in relation to the Trust's interest in a property, the total area in which the Trust has an interest multiplied by the working interest owned by the Trust.

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.

   "Economic Assumptions" will be the prices and costs used in the estimate, namely:

   (a) constant prices and costs as at the last day of the Trust's financial year; and

   (b) forecast prices and costs.

   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.

(c) 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. The Alberta royalty tax credit (ARTC) is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. The Trust qualifies for the maximum ARTC.

5. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

6. "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.

7. "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.

8. "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.

9. "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.

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 following sets forth the benchmark reference prices, as at January 1, 2004, reflected in the Reserves Data. The forecast prices and cost assumptions were provided to the Trust by Sproule, the Trust's independent qualified reserves evaluator.

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).

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 January 1, 2004, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2004
FORECAST PRICES AND COSTS

	OIL					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40 API ($Cdn/Bbl)	Hardisty Heavy 12 API ($Cdn/Bbl)	NATURAL GAS AECO Gas Price ($Cdn/Mmbtu)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast						
2004	29.63	37.99	23.80	6.04	1.5	0.75
2005	26.80	34.24	21.28	5.36	1.5	0.75
2006	25.76	32.87	20.80	4.80	1.5	0.75
2007	26.14	33.37	21.33	4.91	1.5	0.75
2008	26.53	33.87	21.84	4.98	1.5	0.75
2009	26.93	34.38	22.31	5.05	1.5	0.75
2010	27.34	34.90	22.80	5.14	1.5	0.75
2011	27.75	35.43	23.29	5.24	1.5	0.75
2012	28.16	35.96	23.79	5.33	1.5	0.75
2013	28.58	36.50	24.29	5.43	1.5	0.75
2014	29.01	37.05	24.81	5.52	1.5	0.75
2015	29.45	37.61	25.33	5.62	1.5	0.75

Escalation Rate of 1.5% thereafter.

Notes:

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

Constant Prices and Costs

These are prices and costs that are:

(a) Baytex's prices and costs as of December 31, 2003, held constant throughout the estimated lives of the Properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices of 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).

The constant crude oil and natural gas benchmark reference pricing and the exchange rate utilized in the Sproule Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2003
CONSTANT PRICES AND COSTS

	OIL				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40 API ($Cdn/bbl)	Hardisty Heavy 12 API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/Mcf)	EXCHANGE RATE(1) ($US/$Cdn)

December 31, 2003	32.52	40.81	25.95	5.77	0.76

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) The exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Trust for the year ended December 31, 2003, were $6.07/Mcf for natural gas, $39.96/Bbl for crude oil, $35.27/Bbl for natural gas liquids and $21.25/Bbl for heavy oil.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF TRUST NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil			Heavy Oil		
	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved + Probable (1) (Mbbls)	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved + Probable (1) (Mbbls)
December 31, 2002 (2)	3,169	969	4,138	88,329	21,572	109,901
Capital Additions (3)	1,563	670	2,233	7,915	4,528	12,443
Technical Revisions	446	(154)	292	(36,837)	(4,543)	(41,380)
Acquisitions	64	8	72	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production (4)	(528)	—	(528)	(7,523)	—	(7,523)
January 1, 2004	4,714	1,493	6,207	51,884	21,557	73,441

	Natural Gas Liquids			Natural Gas		
	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved+ Probable (1) (Mbbls)	Proved (1) (Mmcf)	Probable (1) (Mmcf)	Proved + Probable (1) (Mmcf)
December 31, 2002 (2)	57	18	75	60,413	11,201	71,614
Capital Additions (3)	48	7	55	14,296	7,581	21,877
Technical Revisions	106	40	146	5,000	957	5,957
Acquisitions	—	—	—	1,242	254	1,496
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production (4)	(28)	—	(28)	(15,351)	—	(15,351)
January 1, 2004	183	65	248	65,600	19,993	85,593

	Oil Equivalent (5)		
	Proved (1) (Mboe)	Probable (1) (Mboe)	Proved + Probable (1) (Mboe)
December 31, 2002 (2)	101,624	24,426	126,050
Capital Additions (3)	11,909	6,469	18,377
Technical Revisions	(35,458)	(4,498)	(39,956)
Acquisitions	271	50	321
Dispositions	—	—	—
Economic Factors	—	—	—
Production (4)	(10,638)	—	(10,638)
January 1, 2004	67,708	26,447	94,154

Notes:

(1) Reserves information as at December 31, 2002 is prepared in accordance with NP 2-B. Probable reserves as at December 31, 2002 represents 50% of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.
(2) As disclosed in the Information Circular dated July 25, 2003 of Baytex Energy Ltd. with respect to the Arrangement resulting in the formation of Baytex Energy Trust. Reserves information based on an independent engineering evaluation of the oil and gas reserves of Baytex as at December 31, 2002 and adjusted by Baytex after giving effect to the transfer of certain oil and gas properties to Crew pursuant to the Arrangement and the sale of oil and natural gas properties in the Ferrier area in March 2003.
(3) Includes Discoveries, Extensions and Improved Recoveries.
(4) Production for the year ended December 31, 2003 excludes production associated with the oil and gas properties transferred to Crew pursuant to the Arrangement and production associated with the oil and gas assets disposed in the Ferrier area.
(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

RECONCILIATION OF TRUST INTEREST RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil			Heavy Oil		
	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved + Probable (1) (Mbbls)	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved + Probable (1) (Mbbls)
December 31, 2002 (2)	3,589	1,142	4,731	100,914	24,471	125,385
Capital Additions (3)	1,931	560	2,491	8,850	4,602	13,452
Technical Revisions	205	(63)	142	(43,502)	(5,467)	(48,969)
Acquisitions	80	10	90	—	—	—
Dispositions	—	—	—	—	—	—
Production (4)	(646)	—	(646)	(8,694)	—	(8,694)
January 1, 2004	5,159	1,649	6,808	57,568	23,606	81,174

	Natural Gas Liquids			Natural Gas		
	Proved (1) (Mbbls)	Probable (1) (Mbbls)	Proved+ Probable (1) (Mbbls)	Proved (1) (Mmcf)	Probable (1) (Mmcf)	Proved + Probable (1) (Mmcf)
December 31, 2002 (2)	81	24	105	75,573	13,521	89,094
Capital Additions (3)	69	12	81	17,925	9,249	27,174
Technical Revisions	144	59	203	6,651	1,593	8,244
Acquisitions	—	—	—	1,386	278	1,664
Dispositions	—	—	—	—	—	—
Production (4)	(34)	—	(34)	(20,360)	—	(20,360)
January 1, 2004	260	95	355	81,175	24,641	105,816

	Oil Equivalent (5)		
	Proved (1) (MBoe)	Probable (1) (MBoe)	Proved + Probable (1) (MBoe)
December 31, 2002 (2)	117,180	27,890	145,070
Capital Additions (3)	13,837	6,715	20,552
Technical Revisions	(42,050)	(5,204)	(47,254)
Acquisitions	311	56	367
Dispositions	—	—	—
Production (4)	(12,768)	—	(12,768)
January 1, 2004	76,510	29,457	105,967

Notes:

(1) Reserves information as at December 31, 2002 is prepared in accordance with NP 2-B. Probable reserves as at December 31, 2002 represents 50% of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.

(2) As disclosed in the Information Circular dated July 25, 2003 of Baytex with respect to the Arrangement resulting in the formation of Baytex Energy Trust. Reserves information based on an independent engineering evaluation of the oil and gas reserves of Baytex as at December 31, 2002 and adjusted by Baytex after giving effect to the transfer of certain oil and natural gas properties to Crew pursuant to the Arrangement and the sale of oil and gas assets in the Ferrier area in March 2003.

(3) Includes Discoveries, Extensions and Improved Recoveries.

(4) Production for the year ended December 31, 2003 excludes production associated with the oil and natural gas properties transferred to Crew pursuant to the Arrangement and production associated with the oil and gas assets disposed in the Ferrier area.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR

PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	2003 ($ Million)
Estimated Future Net Revenue at Beginning of Year	1,310.5
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(138.2)

Net Change in Prices, Production Costs and Royalties Related to Future Production	(89.0)
Changes in Previously Estimated Development Costs Incurred During the Period	126.9
Changes in Estimated Future Development Costs	(20.1)
Capital Additions	215.5
Acquisitions of Reserves	3.8
Dispositions of Reserves	—
Net Change Resulting from Revisions in Quantity Estimates	(746.8)
Accretion of Discount	131.1
Estimated Future Net Revenue at End of Year	793.7

Additional Information Relating to Reserves Data

Proved and Probable 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.

Baytex develops assets in an efficient and methodical fashion to reduce risk by technically assessing the results of a development program before committing additional capital. This staged approach to development means that in some cases it will take longer than two years to develop proved and probable undeveloped reserves. The Trust plans to develop the majority of the proved undeveloped reserves in the Sproule Report over the next four years and also plans to develop the majority of the probable undeveloped reserves over the next four years.

Significant Factors or Uncertainties

Baytex has a significant amount of proved non-producing and proved undeveloped reserves assigned to the Tangleflags heavy oil property in Saskatchewan and to the Ardmore and Cold Lake heavy oil Properties in Alberta. At the current prices, these well re-completions and new wells are economic; however should oil prices fall materially, these activities may not be economic and Baytex could defer their implementation.

Future Development Costs

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

	Forecast Prices and Costs		Constant Prices and Costs
Year	**Proved Reserves ($ Million)**	**Proved Plus Probable Reserves ($ Million)**	**Proved Reserves ($ Million)**
2004	74.7	89.8	74.7
2005	27.2	41.1	26.8
2006	17.8	38.8	17.2
2007	10.6	27.6	10.2
2008	1.6	1.7	1.5
Total Undiscounted (all years)	134.9	203.7	133.1
Total Discounted at 10%/year	118.8	174.4	117.4

Baytex expects to fund the development costs of the reserves through a combination of internally generated cash flow, debt and sale of Trust Units. The Trust withholds approximately 30 - 40% of cash flow to assist in funding development activities.

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

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Baytex does not anticipate that interest or other funding costs would make development of any property uneconomic.

Estimated future well abandonment costs related to Baytex have been taken into account by Sproule in determining reserves that should be attributed to Baytex. In determining the aggregate future net revenue, reasonable estimated future well abandonment costs, net of downhole equipment salvage value, were deducted from the gross revenue amount.

Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.

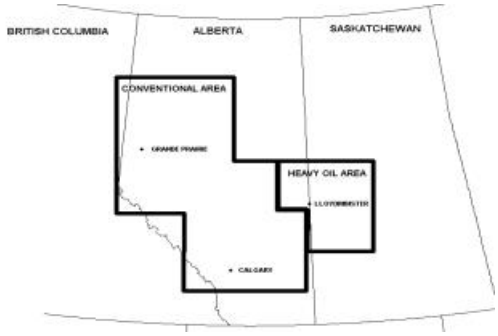
The extended character of all factual data supplied to Sproule was accepted by Sproule as represented. No field inspection was conducted.

Other Oil and Gas Information

Oil and Natural Gas Properties

The following is a description of the Trust's principal oil and natural gas properties on production or under development as at January 1, 2004. The term "net", when used to describe the Trust's share of production, means the total of the Trust's working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at January 1, 2004, based on forecast cost and price assumptions (gross) as evaluated in the Sproule Report (see "*Description of the Business and Operations – Oil and Natural Gas Reserves* "). Unless otherwise specified, gross and net acres and well count information are as at January 1, 2004. Information in respect of current production is average production, net to the Trust, for the year ended December 31, 2003, except where otherwise indicated. Information related to land holdings is at December 31, 2003.

The crude oil and natural gas properties in which Baytex has an interest are within two districts in Alberta and Saskatchewan. Each district constitutes a well-balanced portfolio of operated Properties and development prospects with considerable upside potential.



Heavy Oil District

The Heavy Oil District accounts for approximately two-thirds of the Trust's current production and approximately three-quarters of reserves. Heavy oil operations consist largely of cold conventional production from wells with multi-zone potential. Production is generated primarily from vertical, slant and horizontal wells using progressive cavity pump technology to generate large volumes of heavy oil combined with gas, water and sand. Production from these wells usually averages between 40 and 100 Bbls/d of low gravity crude ranging from 12 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States for upgrading into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt.

During 2003, production in the Heavy Oil District averaged 25,676 Boe/d made up of 23,911 Bbls/d of heavy oil and 10.6 Mmcf/d of natural gas. The Trust drilled 174 gross (165.2 net) wells in the district, resulting in 159 gross (150.2 net) oil wells, four gas wells, four service wells, and seven dry and abandoned wells for a success rate of 96 percent.

The Trust possesses a vast inventory of development projects in the west central Saskatchewan heavy oil region and the Cold Lake, Ardmore and Seal areas of north central Alberta. The ability to generate replacement production through conventional drilling methods allows the Trust to better control the cost and timing of its capital investments.

The Trust will continue to build value through internal property development and selective acquisitions. Future heavy oil activity will focus on the development of the Seal and Ardmore Properties along with continued infill drilling at adjacent Cold Lake and throughout the Saskatchewan Properties.

Ardmore: Ardmore is one of the key heavy oil development and production areas for the Trust. Acquired in 2002, this year-round access area generated approximately 3,100 Bbls/d of oil in 2003, with current production in excess of 4,500 Bbls/d. Since acquiring this property, the Trust has applied leading-edge heavy oil drilling and production technology to improve production and reduce cost. Wells in the area are 100 percent owned and operated by Baytex and they are able to produce up to 300 Bbls/d of 11 to 13 API heavy crude oil primarily from the McLaren and Sparky formations. The Trust drilled 48 gross (47.6 net) oil wells in the area during 2003, resulting in 47 gross (46.6 net) oil wells and one service well. The Trust holds approximately 32,000 net acres of 100 percent working interest undeveloped land in this area.

Cold Lake: Baytex acquired the Cold Lake heavy oil property in 2001. This year-round drilling area is located on Cold Lake First Nations Land with heavy oil production generated largely from the Colony formation. Average production was 935 Bbls/d during 2003. The Trust drilled 15 gross (13.5 net) operated oil wells in the Cold Lake area during 2003 and holds 19,500 net acres of undeveloped land.

Seal: The Seal property is a highly prospective heavy oil area for the Trust. The property is located in the Peace River oilsands area of northwest Alberta. The Trust holds 100 percent working interests in approximately 58 sections of land of which 44 sections were acquired in 2003. The Seal oil deposits can be produced through horizontal wells using primary production technology without the use of capital intensive steam injection methods. The Trust completed a seven-well test program during the first quarter of 2004. A development plan for a pilot production is being designed for the second half of 2004 and the winter of 2005.

Tangleflags: Baytex acquired the Tangleflags property through the acquisition of Bellator Exploration Inc. in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Provincial government regulations generally prohibit production from more than one formation at a time. As such, this property possesses long-term development potential with a considerable number of up-hole completion opportunities. Average production during 2003 was 4,940 Bbls/d

of heavy oil and 1.6 Mmcf/d of natural gas.

Carruthers: The Carruthers property was obtained by Baytex in 1997 through the merger with Dorset Exploration Ltd. The property consists of two separate pools in the Cummings formation. During 2003, average production was 3,300 Bbls/d of heavy oil and 0.6 Mmcf/d of natural gas. The Trust drilled 35 gross (29.75 net) oil wells in the Carruthers area during 2003, resulting in 33 gross (27.75 net) oil wells and 2 dry holes for an overall drilling success rate of 94 percent. The Trust has continued to develop the southern pool since 1999, with 15 to 20 locations planned for 2004.

Marsden/Silverdale: The Marsden/Silverdale area of Saskatchewan is characterized by quality oil of 13 to 18 API and production averaging 100 Bbls/d per well. The lighter gravity oil allows production to be flow-lined to treating and disposal facilities thereby reducing trucking costs. Lower trucking costs, combined with characteristically low sand production, result in lower overall operating costs. Production averaged 3,400 Bbls/d of oil and 1.1 Mmcf/d of natural gas during 2003. The Trust drilled 9 oil wells in the area during 2003, with 100 percent success. The Trust has approximately 12,000 net acres of undeveloped land in the Marsden/Silverdale area.

Conventional Oil and Gas District

The Conventional Oil and Gas District includes Properties located in Alberta producing light and medium gravity crude oil, natural gas and related liquids. Production in this district averaged 11,010 Boe/d for the year ended December 31, 2003, consisting of 2,273 Bbls/d of oil and natural gas liquids and 52.4 Mmcf/d of natural gas.

Excluding production from the Ferrier area, which was sold in March 2003, and production from the Properties which were transferred to Crew pursuant to the Arrangement, production in this district averaged 1,860 Bbls/d of oil and natural gas liquids and 45.2 Mmcf/d of natural gas, or 9,400 Boe/d during 2003.

Leahurst: Baytex began operations in the Leahurst area in 1993. Production in the area is primarily natural gas from the Belly River and lower Mannville formations. The Trust holds approximately 19,000 net acres of land in the area, interests in two gas plants and a 100-km gathering system. In 2003, the Trust drilled 7.8 net successful natural gas wells. The Leahurst area has year-round access, which allows Baytex to conduct continuous development activities. The Trust's average production for 2003 was 7.3 Mmcf/d of natural gas in this area.

Red Earth/Goodfish: Baytex commenced operations in this area through the merger with Dorset Exploration Ltd. in 1997. Production includes light oil from the Slave Point and Granite Wash formations and natural gas from the Bluesky formation. In 2003, the Trust drilled 10.2 net wells in the area resulting in 5 net oil wells and 5 net natural gas wells. The Trust holds approximately 58,000 net acres of undeveloped land in this area. The Trust's average production in 2003 was 1,000 Bbls/d of light oil and 9.8 Mmcf/d of natural gas.

Nina/Darwin: Baytex began operations in the Darwin area in 1998, targeting natural gas from the Bluesky formation. Production from Nina commenced in March 2001. The Trust holds approximately 34,000 net acres of land in the area. Average production in this area in 2003 was 4.9 Mmcf/d of natural gas.

Bon Accord: The Bon Accord natural gas property was acquired by Baytex in 1997 through the merger with Dorset Exploration Ltd. The Trust utilizes 3-D seismic technology to identify gas-producing zones in the Mannville, Nisku and Sparky formations. The Trust drilled 8 wells in the Bon Accord area during 2003, resulting in 5 natural gas wells and 1 oil well. Average production was 8.4 Mmcf/d of natural gas and 360 Bbls/d of oil and natural gas liquids. The Trust has approximately 13,000 net acres of land in this area.

Hamburg/Chinchaga: Baytex constructed a natural gas processing plant in this area during 2003 with processing capacity of 8.0 Mmcf/d. The Trust's production in the area averaged approximately 5 Mmcf/d during 2003, leaving approximately 3 Mmcf/d of plant capacity for third-party processing which is expected to be filled by the end of the first quarter of 2004. The Trust has had success targeting natural gas in the Slave Point, Bluesky and Gilwood formations. Drilling activity in 2003 resulted in two successful natural gas wells. Net landholdings in the area total 17,500 acres as at December 31, 2003.

The following table indicates the Trust's average daily production from its important fields for the year ended December 31, 2003.

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)
Tangleflags	—	4,940	1,551
Carruthers	—	3,331	628
Ardmore	—	3,123	—
Lashburn	—	2,165	607
Silverdale	—	2,023	1,094
Marsden	—	1,334	—
Neilburg	—	1,145	—
Poundmaker	—	1,232	3,082
Red Earth	973	—	67
Sounding Lake	394	—	—
Bon Accord	359	—	8,049
Goodfish	—	—	8,499
Leahurst	—	—	7,268
Darwin/Nina	—	—	4,961
Richdale	—	—	4,443
Viking	—	—	4,216
Ferrier	—	—	3,524
Tangent	—	—	2,578

Other	547	4,618	12,085
Total	2,273	23,911	63,012

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Trust has a working interest as at December 31, 2003.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	299	240.37	242	195.5	340	248.89	220	156.75
British Columbia	0	0	1	0	1	0	11	4.65
Saskatchewan	782	698.91	542	480.39	49	39.02	47	41.92
Total	1,081	939.28	785	675.89	390	287.91	278	203.32

Properties with no Attributable Reserves

The following table sets out the Trust's undeveloped land holdings as at December 31, 2003.

	Undeveloped Acres	
	Gross	Net
Alberta	585,775	498,191
British Columbia	71,834	47,920
Saskatchewan	194,285	182,708
Total	851,894	728,819

The Trust expects that rights to explore develop and exploit 124,611 net acres of its undeveloped land holdings, absent further action, will expire by December 31, 2004**.**

Forward Contracts

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2003 see Notes 15 and 16 to the Consolidated Financial Statements on pages 58 and 59 contained in the Trust's Annual Report which pages are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

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

	Abandonment and Reclamation Costs escalated at 1.5% per year Undiscounted ($ Million)	Abandonment and Reclamation Costs escalated at 1.5% per year Discounted at 8% ($ Million)
Total as at December 31, 2003	271.4	66.4
Anticipated to be paid in 2004	4.9	4.7
Anticipated to be paid in 2005	5.0	4.4
Anticipated to be paid in 2006	4.9	4.1

Baytex will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Baytex estimates the costs to abandon and reclaim all of its producing and shut in wells, facilities, and pipelines. In the table above, no estimate of salvage value is netted against the estimated cost. Baytex estimates the amount and timing of future abandonment and reclamation expenditures at an operating area level, with each operating area assigned an average cost per well to abandon and reclaim wells in that area. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The number of net wells for which Sproule estimated Baytex will incur reclamation and abandonment costs is 1,002.4 non-producing wells and 1,567.5 producing wells. This estimate of total wells includes all proved undeveloped and probable undeveloped wells which had not been drilled as of January 1, 2004. 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 reserves. 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 well, pipelines and facility reclamation costs, which was estimated to be $171.7 million ($43.2 million discounted at 8%), was not deducted in estimating future net revenue.

Tax Horizon

The Trust is classified as a unit trust for income tax purposes, and is taxable on income not distributed to public Unitholders. The Trust has and expects to allocate all of its taxable income to Unitholders. Accordingly, no provision for income taxes is required at the Trust level and the information for the most recent oil and gas reserves has been presented on a pre-tax basis.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Trust's activities for the year ended December 31, 2003.

Property acquisition costs		
Proved Properties	$	6,644
Unproved Properties		14,138
Exploration costs		8,578
Development costs		157,396
Total	$	186,756

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Trust participated during the year ended December 31, 2003.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	—	—	173	158.9
Natural Gas	5	5.0	62	56.4
Service	—	—	7	5.1
Dry	6	5.0	13	13.0
Total:	11	10.0	255	233.4

Production Estimates

The following table sets out the volume of the Trust's production estimated for the year ended December 31, 2004 which is reflected in the estimate of future net revenue disclosed in the tables contained under "- *Disclosure of Reserves Data*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mmcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
2004	1,856.5	28,441.0	50.2	186.1	38,850.9

Production History, Prices Received And Capital Expenditures

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	Quarter Ended 2003			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production				
Light and Medium Crude Oil (Bbls/d)	1,982	1,989	2,167	2,969
Heavy Oil (Bbls/d)	24,400	25,123	22,816	23,278
Gas (Mcf/d)	58.9	61.8	57.5	74.0
Combined (Boe/d)	36,195	37,412	34,574	38,580
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	36.41	34.43	37.13	45.41
Heavy Oil ($/Bbl)	19.24	21.20	19.84	24.55
Gas ($/Mcf)	5.37	5.62	6.05	7.02
Combined ($/Boe)	23.78	25.35	25.57	32.07
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	5.44	5.96	7.21	8.50
Heavy Oil ($/Bbl)	2.70	3.32	3.37	4.63
Gas ($/Mcf)	1.22	1.14	1.51	1.64
Combined ($/Boe)	4.12	4.43	5.22	6.66
Production Costs				
Light and Medium Crude Oil ($/Bbl)	10.42	11.31	8.91	4.40
Heavy Oil ($/Bbl)	7.44	7.10	7.65	7.21
Gas ($/Mcf)	0.72	0.84	0.71	0.66

Combined ($/Boe)	6.74	6.75	6.77	5.91
Netback Received				
Light and Medium Crude Oil ($/Bbl)	20.54	17.11	21.01	32.51
Heavy Oil ($/Bbl)	9.11	10.78	8.82	12.71
Gas ($/Mcf)	3.44	3.46	3.83	4.72
Combined ($/Boe)	12.92	14.16	13.58	19.49

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 the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to an equal share of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units shall 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 the Trust to redeem any or all of the Trust Units held by such holder (see "*Redemption Right*") and to one vote at all meetings of Trust Unitholders for each Trust Unit held.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in either Baytex or the Trust. As holders of Trust Units in the Trust, the Trust Unitholders do 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 price per Trust Unit will be a function of anticipated distributable income from Baytex and the ability of Baytex to effect long term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not

limited to, interest rates, exchange rates, commodity prices and the ability of the Trust to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units.

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, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Special Voting Units

In order to allow the Trust flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation of Special Voting Units which enables the Trust 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 other subsidiaries of the Trust in connection with other exchangeable share transactions.

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

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued one Special Voting Right to Valiant Trust Company for the benefit of every Person who received Exchangeable Shares pursuant to the Arrangement. See "*Additional Information Respecting Baytex – Share C*apital" below.

Trust Unitholder Limited Liability

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

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

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

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 of Baytex 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

The Trustee may declare payable to the Unitholders all or any part of the net income of the Trust earned from interest income on the Notes and from the income generated under the NPI Agreement, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust. In addition, Trust Unitholders may, at the discretion of the Board of Directors of Baytex, receive distributions in respect of prepayments of principal on the Notes made by Baytex to the Trust before the maturity of the Notes. See "*Selected Consolidated Financial Information – Cash Distributions*" below.

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust 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 the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (i) 90% 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 the Trust 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" will be 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 shall 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 shall 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 shall 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 Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Trust Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust 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 shall not exceed $100,000; provided that the Trust may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption; and (ii) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes, (herein referred to as "Redemption Notes") shall have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Trust Unitholder, the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which Baytex considers, in its sole discretion, provides 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 Trust Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised

Redemption Price") equal to 90% 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 Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall 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 Trust Unitholders in connection with a 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 registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Trust Unitholders

It is in the best interest of Unitholders that the Trust qualifies as a "unit trust" and a "mutual fund trust" under the Tax Act. Certain provisions of the Tax Act require that the Trust not be established nor maintained primarily for the benefit of Non-Residents. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Trust Unitholders who are Non-Residents. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. If at any time the Trust becomes aware that the beneficial owners of 50% or more of the Trust Units then outstanding are or may be Non-Residents or that such a situation is imminent, the Trust shall take such action as may be necessary to carry out the intentions evidenced therein. As at April 30, 2004, approximately 29% of the Trust Units were held by Non-residents.

Meetings of Trust Unitholders

The Trust Indenture provides that meetings of Trust Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "*Amendments to the Trust Indenture*"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Trust Unitholders will be called and held annually for, among other things, the election of the directors of Baytex and the appointment of the auditors of the Trust.

A meeting of Trust 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% 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.

Trust Unitholders may attend and vote at all meetings of Trust Unitholders either in person or by proxy and a proxyholder need not be a Trust Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding Trust Units shall 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 shall 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 Trust Unitholders in accordance with the requirements of applicable laws.

Reporting to Trust Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, are mailed by the Trustee to Trust Unitholders and the unaudited interim financial statements of the Trust are mailed to Trust Unitholders within the periods prescribed by securities legislation. The year end of the Trust is December 31.

The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

Takeover Bids

The Trust Indenture contains provisions to the effect that if a takeover bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover 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 Trust Unitholders who did not accept the takeover bid on the terms offered by the offeror.

The Trustee

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

The initial term of the Trustee's appointment is until the third annual meeting of Trust Unitholders. The Unitholders shall, at the third annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trust. The Trustee may also be removed by Special Resolution of the Trust 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 of Baytex has generally been delegated the significant management decisions of the Trust. 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 the material contracts of the

Trust; (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 redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the Trust Fund or any Subsequent Investments; (viii) 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 shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, entering into the Administration Agreement 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, the property of the Trust 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 adviser 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, adviser or legal counsel, and notwithstanding any other provision of the Trust Indenture, the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively

deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. 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 Special Resolution.

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

(a) ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;

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

(c) ensuring that such additional protection is provided for the interests of Trust 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 the Trust or any offering document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust 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 the Trust Unitholders are not prejudiced thereby.

Termination of the Trust

The Trust Unitholders may vote to terminate the Trust at any meeting of the Trust 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% of the outstanding Trust Units; (b) a quorum of 50% 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 Trust Unitholders.

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

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 amend the rights, privileges, restrictions and conditions attaching to any class of Baytex's shares in a manner which may be prejudicial to the Trust,

without the approval of the Unitholders by Special Resolution at a meeting of Unitholders called for that purpose.

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY LTD.

Management of the Trust

The name, municipality of residence, principal occupation for the prior five years of each of the directors and officers of Baytex are as follows:

Name and Municipality of Residence	Position with Baytex	Principal Occupation
Raymond T. Chan Calgary, Alberta	President, Chief Executive Officer and Director	President and Chief Executive Officer of Baytex since September 2003; prior thereto, Senior Vice President and Chief Financial Officer of Baytex since October 1998.
John A. Brussa (2) (3) Calgary, Alberta	Director	Partner, Burnet, Duckworth & Palmer LLP (a law firm).
W.A. Blake Cassidy (1) Calgary, Alberta	Director	Retired banker.
Edward Chwyl(2) (3) Victoria, B.C.	Chairman	Independent businessman since May 2002; prior thereto Chairman of the Board of Ventus Energy Ltd. since January 1999; prior thereto Chief Executive Officer of Marathon Oil Canada Ltd. since August 1998; prior thereto President and Chief Executive Officer of Tarragon Oil and Gas Limited.
Naveen Dargan(1) (2) Calgary, Alberta	Director	Independent businessman since June 2003; prior thereto Senior Managing Director of Raymond James Ltd. and predecessor companies.

Name and Municipality of Residence	Position with Baytex	Principal Occupation
Dale O. Shwed(1) (3) Calgary, Alberta	Director	President and Chief Executive Officer of Crew Energy Inc. since September 2003; prior thereto President and Chief Executive Officer of Baytex.
Daniel G. Belot Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Baytex since September 2003; prior thereto Manager, Investor Relations, Pengrowth Energy Trust from 2001 to 2003; prior thereto, Corporate and Investment Banker with Scotia Capital.
Randal J. Best Calgary, Alberta	Vice President, Corporate Development	Vice President, Corporate Development of Baytex since September 2003; prior thereto Managing Director of Waterous Securities Inc. from 2000 to 2003; prior thereto President and CEO of Enercap Corporation, a private investment company.

Ralph W. Gibson Calgary, Alberta	Vice President, Marketing	Vice President, Marketing of Baytex since September 2001; prior thereto Vice President, Crude Oil of Canpet Energy Group Inc. since November 2000; prior thereto Vice President, Marketing of Ranger Oil Limited.
Richard W. Naden Calgary, Alberta	Vice President, Engineering & Operations	Vice-President, Engineering & Operations of Baytex since September 2003; prior thereto, Vice President, Production of Baytex since October 1997.
Shannon M. Gangl Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP since January 1999; prior thereto Associate, Burnet, Duckworth & Palmer LLP.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves Committee.
(4) Baytex's directors hold office until the next annual general meeting of the Corporation's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(5) The period of time served as a director of Baytex includes the period of time served as a director of Baytex prior to the Arrangement, where applicable.
(6) Mr. Shwed was a director of Echelon Energy Inc., a private company incorporated under the ABCA. In September 1999, a receiver manager was appointed over the assets of Echelon.

As at March 31, 2004, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 729,438 Trust Units, or approximately 1.2% of the issued and outstanding Trust Units. In addition, as at March 31, 2004, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 605,129 Exchangeable Shares (approximately 31% of the issued and outstanding Exchangeable Shares).

Conflicts of Interest

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 the Trust or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex and the Trust. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the ABCA.

Personnel

As at December 31, 2003, Baytex employed 95 head office employees and 17 field office employees.

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, there are 62,710,251 Trust Units and 1,968,211 Exchangeable Shares issued and outstanding. The Trust is the sole holder of the issued and outstanding common shares of Baytex. The Trust is also the sole holder of the Notes.

Baytex Common Shares

Each Baytex common share entitles its holder 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 of Baytex 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 shall 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. At December 31, 2003, all of the common shares of Baytex are owned by the Trust.

Exchangeable Shares

The following is a summary description of the material provisions of the Exchangeable Shares and the related ancillary and indirect rights of holders of Exchangeable Shares under the terms of the Voting and Exchange Trust Agreement and the Support Agreement.

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 granted to the Voting and Exchange Trust Agreement Trustee) 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. Fractional Trust Units will not be delivered on any exchange of Exchangeable Shares. In the event that the Exchange Ratio in effect at the time of an exchange would otherwise entitle a holder of Exchangeable Shares to a fractional Trust Unit, the number of Trust Units to be delivered are rounded down to the nearest whole number of Trust Units. Holders of Exchangeable Shares will not receive cash distributions from the Trust or Baytex. Rather, the Exchange Ratio will be adjusted to account for distributions paid to Unitholders.

Ranking

The Exchangeable Shares rank rateably with shares of any other series of exchangeable shares of Baytex and prior to any common shares and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends, if any, that have been declared and the distribution of assets in the event of the liquidation, dissolution or winding-up of Baytex.

Dividends

Holders of Exchangeable Shares are entitled to receive cash dividends if, as and when declared by the Board of Directors of Baytex. Baytex anticipates that it may from time to time declare dividends on the Exchangeable Shares up to but not exceeding any cash distributions on the Trust Units into which such Exchangeable Shares are exchangeable. In the event that any such dividends are paid, the Exchange Ratio will be correspondingly reduced to reflect such dividends.

Certain Restrictions

Baytex will not, without obtaining the approval of the holders of the Exchangeable Shares as set forth below under the subheading " *Amendment and Approval*":

(a) pay any dividend on the common shares or any other shares ranking junior to the common shares, other than stock dividends payable in common shares or any other shares ranking junior to the Exchangeable Shares;

(b) redeem, purchase or make any capital distribution in respect of the common shares of Baytex or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of Baytex ranking equally with the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d) issue any shares, other than Exchangeable Shares or common shares, which rank superior to the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

The above restrictions shall not apply if all declared dividends on the outstanding Exchangeable Shares have been paid in full.

Liquidation or Insolvency of Baytex

In the event of the liquidation, dissolution or winding-up of Baytex or any other proposed distribution of the assets of Baytex among its shareholders for the purpose of winding up its affairs, a holder of Exchangeable Shares will be entitled to receive from Baytex, in respect of each such Exchangeable Share, that number of Trust Units equal to the Exchange Ratio as at the effective date of such event.

Upon the occurrence of such an event, the Trust and ExchangeCo will each have the overriding right to purchase all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by the Trust or any subsidiary of the Trust) at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time and, upon the exercise of this right, the holders thereof will be obligated to sell such Exchangeable Shares to the Trust or ExchangeCo, as applicable. This right may be exercised by either the Trust or ExchangeCo.

Automatic Exchange Right on Liquidation of the Trust

The Voting and Exchange Trust Agreement provides that in the event of a Trust liquidation event, as described below, the Trust or ExchangeCo will be deemed to have purchased all outstanding Exchangeable Shares and each holder of Exchangeable Shares will be deemed to have sold their Exchangeable Shares immediately prior to such Trust liquidation event at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time. "Trust liquidation event" means:

- any determination by the Trust to institute voluntary liquidation, dissolution or winding-up proceedings in respect of the Trust or to effect any other distribution of assets of the Trust among the Unitholders for the purpose of winding up its affairs; or

- the earlier of, the Trust's receiving notice of and the Trust's otherwise becoming aware of, any threatened or instituted claim, suit, petition or other proceedings with respect to the involuntary liquidation, dissolution or winding up of the Trust or to effect any other distribution of assets of the Trust among the Unitholders for the purpose of winding up its affairs in each case where the Trust has failed to contest in good faith such proceeding within 30 days of becoming aware thereof.

Retraction of Exchangeable Shares by Holders and Retraction Call Right

Subject to the Retraction Call Right of the Trust and ExchangeCo described below, a holder of Exchangeable Shares will be entitled at any time to require Baytex to redeem any or all of the Exchangeable Shares held by such holder for a retraction price

(the "Retraction Price") per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the date of redemption (the "Retraction Date"), to be satisfied by the delivery of such number of Trust Units. Fractional Trust Units will not be delivered. Any amount payable on account of the Retraction Price that includes a fractional Trust Unit will be rounded down to the nearest whole number of Trust Units. Holders of the Exchangeable Shares may request redemption by presenting to Baytex or the transfer agent for the Exchangeable Shares a certificate or certificates representing the number of Exchangeable Shares the holder desires to have redeemed, together with a duly executed retraction request and such other documents as may be reasonably required to effect the redemption of the Exchangeable Shares. The redemption will become effective on the Retraction Date, which will be three Business Days after the date on which Baytex or the transfer agent receives the retraction notice.

When a holder requests Baytex to redeem the Exchangeable Shares, the Trust and ExchangeCo will have an overriding right (the "Retraction Call Right") to purchase on the Retraction Date all but not less than all of the Exchangeable Shares that the holder has requested Baytex to redeem at a purchase price per Exchangeable Share equal to the Retraction Price, to be satisfied by the delivery of that number of Trust Units equal to the Exchange Ratio at such time. At the time of a Retraction Request by a holder of Exchangeable Shares, Baytex will immediately notify the Trust and ExchangeCo. The Trust or ExchangeCo must then advise Baytex within two business days as to whether the Retraction Call Right will be exercised. A holder may revoke his or her Retraction Request at any time prior to the close of business on the last business day immediately preceding the Retraction Date, in which case the holder's Exchangeable Shares will neither be purchased by the Trust or ExchangeCo nor be redeemed by Baytex. If the holder does not revoke his or her Retraction Request, the Exchangeable Shares that the holder has requested Baytex to redeem will on the Retraction Date be purchased by the Trust or ExchangeCo or redeemed by Baytex, as the case may be, in each case at a purchase price per Exchangeable Share equal to the Retraction Price. In addition, a holder of Exchangeable Shares may elect to instruct the Voting and Exchange Trust Agreement Trustee to exercise the optional exchange right (the "Optional Exchange Right") to require the Trust or ExchangeCo to acquire such holder's Exchangeable Shares in circumstances where neither the Trust nor ExchangeCo have exercised the Retraction Call Right. See "*Voting and Exchange Trust Agreement - Optional Exchange Right*".

The Retraction Call Right may be exercised by either the Trust or ExchangeCo. If, as a result of solvency provisions of applicable law, Baytex is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, Baytex will redeem only those Exchangeable Shares tendered by the holder as would not be contrary to such provisions of applicable law. The holder of any Exchangeable Shares not redeemed by Baytex will be deemed to have required the Trust to purchase such unretracted Exchangeable Shares in exchange for Trust Units on the Retraction Date pursuant to the Optional Exchange Right. See "*Voting and Exchange Trust Agreement - Optional Exchange Right*".

Redemption of Exchangeable Shares

Subject to applicable law and the Redemption Call Right of the Trust and ExchangeCo, Baytex:

(a) will, on the tenth anniversary of the Effective Date, subject to extension of such date by the Board of Directors of Baytex (the "Automatic Redemption Date"), redeem all but not less than all of the then outstanding Exchangeable Shares for a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the last Business Day prior to that Redemption Date (as that term is defined below) (the "Redemption Price"), to be satisfied by the delivery of such number of Trust Units;

(b) may, on the second anniversary of the Effective Date (the "Optional Redemption Date"), redeem all but not less than all outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share at the last Business Day prior to that Redemption Date (as that term is defined below), to be satisfied by the delivery of Trust Units;

(c) may, on any date that is within the first 90 days of any calendar year commencing in 2004 (the "Annual Redemption Date"), redeem up that number of Exchangeable Shares equal to 40% of the Exchangeable Shares outstanding on the Effective Date for the Redemption Price per Exchangeable Share at the last Business Day prior to that Redemption Date (as that term is defined below), to be satisfied by the delivery of Trust Units; and

(d) may, at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1 million (other than Exchangeable Shares held by the Trust and its subsidiaries and as such shares may be adjusted from time to time) (the "De Minimus Redemption Date" and, collectively with the Automatic

Redemption Date, optional Redemption Date and Annual Redemption Date, a "Redemption Date"), redeem all but not less than all of the then outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share (unless contested in good faith by the Trust).

Baytex will, at least 90 days prior to any Redemption Date, provide the registered holders of the Exchangeable Shares with written notice of the prospective redemption of the Exchangeable Shares by Baytex.

The Trust and ExchangeCo have the right (the "Redemption Call Right"), notwithstanding a proposed redemption of the Exchangeable Shares by Baytex on the applicable Redemption Date, pursuant to the Exchangeable Share Provisions, to purchase on any Redemption Date all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by the Trust or its subsidiaries) in exchange for the Redemption Price per Exchangeable Share and, upon the exercise of the Redemption Call Right, the holders of all of the then outstanding Exchangeable Shares will be obliged to sell all such shares to the Trust or ExchangeCo, as applicable. If either the Trust or ExchangeCo exercises the Redemption Call Right, then Baytex's right to redeem the Exchangeable Shares on the applicable Redemption Date will terminate. The Redemption Call Right may be exercised by either the Trust or ExchangeCo.

Voting Rights

Except as required by applicable law, the holders of the Exchangeable Shares are not entitled as such to receive notice of or attend any meeting of the shareholders of Baytex or to vote at any such meeting. Holders of Exchangeable Shares have the notice and voting rights respecting meetings of the Trust that are provided in the Voting and Exchange Trust Agreement. See "*Voting and Exchange Trust Agreement - Voting Rights*".

Amendment and Approval

The rights, privileges, restrictions and conditions attaching to the Exchangeable Shares may be changed only with the approval of the holders thereof. Any such approval or any other approval or consent to be given by the holders of the Exchangeable Shares will be sufficiently given if given in accordance with applicable law and subject to a minimum requirement that such approval or consent be evidenced by a resolution passed by not less than two-thirds of the votes cast thereon (other than shares beneficially owned by the Trust, or any of its subsidiaries and other affiliates) at a meeting of the holders of the Exchangeable Shares duly called and held at which holders of at least 10% of the then outstanding Exchangeable Shares are present in person or represented by proxy. In the event that no such quorum is present at such meeting within one-half hour after the time appointed therefor, then the meeting will be adjourned to such place and time (not less than ten days later) as may be determined at the original meeting and the holders of Exchangeable Shares present in person or represented by proxy at the adjourned meeting will constitute a quorum thereat and may transact the business for which the meeting was originally called. At the adjourned meeting, a resolution passed by the affirmative vote of not less than two-thirds of the votes cast thereon (other than shares beneficially owned by the Trust or any of its subsidiaries and other affiliates) will constitute the approval or consent of the holders of the Exchangeable Shares.

Actions by the Trust Under the Support Agreement and the Voting and Exchange Trust Agreement

Under the Exchangeable Share Provisions, Baytex has agreed to take all such actions and do all such things as are necessary or advisable to perform and comply with its obligations under, and to ensure the performance and compliance by the Trust and ExchangeCo with their obligations under, the Support Agreement and the Voting and Exchange Trust Agreement.

Non-Resident and Tax-Exempt Holders

The obligation of Baytex, the Trust or ExchangeCo to deliver Trust Units to a Non-Resident holder in respect of the exchange of such holder's Exchangeable Shares may be satisfied by delivering such Trust Units to the transfer agent who shall sell such Trust Units on the stock exchange on which they are listed and deliver the proceeds of sale to the Non-Resident holder.

VOTING AND EXCHANGE TRUST AGREEMENT

Voting Rights

In accordance with the Voting and Exchange Trust Agreement, the Trust has issued one (1) Special Voting Right to Valiant Trust Company, the Voting and Exchange Trust Agreement Trustee, for the benefit of the holders (other than the Trust and ExchangeCo) of the Exchangeable Shares. The Special Voting Right carries a number of votes, exercisable at any meeting at which Trust Unitholders are entitled to vote, equal to one vote for each Exchangeable Share outstanding . With respect to any written consent sought from the Trust Unitholders, each vote attached to the Special Voting Right will be exercisable in the same manner as set forth above.

Each holder of an Exchangeable Share on the record date for any meeting at which Trust Unitholders are entitled to vote will be entitled to instruct the Voting and Exchange Trust Agreement Trustee to exercise that number of votes attached to the Special Voting Right which relate to the Exchangeable Shares held by such holder. The Voting and Exchange Trust Agreement Trustee will exercise each vote attached to the Special Voting Right only as directed by the relevant holder and, in the absence of instructions from a holder as to voting, will not exercise such votes.

The Voting and Exchange Trust Agreement Trustee is required to send to the holders of the Exchangeable Shares the notice of each meeting at which the Trust Unitholders are entitled to vote, together with the related meeting materials and a statement as to the manner in which the holder may instruct the Voting and Exchange Trust Agreement Trustee to exercise the votes attaching to the Special Voting Right, at the same time as the Trust sends such notice and materials to the Trust Unitholders. The Voting and Exchange Trust Agreement Trustee is also required to send to the holders copies of all information statements, interim and annual financial statements, reports and other materials sent by the Trust to the Trust Unitholders at the same time as such materials are sent to the Trust Unitholders. To the extent such materials are provided to the Voting and Exchange Trust Agreement Trustee by the Trust, the Voting and Exchange Trust Agreement Trustee will also send to the holders all materials sent by third parties to Trust Unitholders, including dissident proxy circulars and tender and exchange offer circulars, as soon as possible after such materials are first sent to Trust Unitholders.

All rights of a holder of Exchangeable Shares to exercise votes attached to the Special Voting Right will cease upon the exchange of all such holder's Exchangeable Shares for Trust Units. With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making necessary amendments or curing ambiguities or clerical errors (in each case provided that the Board of Directors of ExchangeCo and Baytex are of the opinion that such amendments are not prejudicial to the interests of the holders of the Exchangeable Shares), the Voting and Exchange Trust Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Optional Exchange Right

Upon the occurrence and during the continuance of:

(a) an Insolvency Event; or

(b) circumstances in which the Trust or ExchangeCo may exercise a Call Right, but elect not to exercise such Call Right,

a holder of Exchangeable Shares will be entitled to instruct the Trustee to exercise the Optional Exchange Right with respect to any or all of the Exchangeable Shares held by such holder, thereby requiring the Trust or ExchangeCo to purchase such Exchangeable Shares from the holder. Immediately upon the occurrence of (i) an Insolvency Event, (ii) any event which will, with the passage of time or the giving of notice, become an Insolvency Event, or (iii) the election by the Trust and ExchangeCo not to exercise a Call Right which is then exercisable by the Trust and ExchangeCo, Baytex, the Trust or ExchangeCo will give notice thereof to the Trustee. As soon as practicable thereafter, the Trustee will then notify each affected holder of Exchangeable Shares (who has not already provided instructions respecting the exercise of the Optional Exchange Right) of such event or potential event and will advise such holder of its rights with respect to the Optional Exchange Right.

The purchase price payable by the Trust or ExchangeCo for each Exchangeable Share to be purchased under the Optional Exchange Right will be satisfied by the issuance of that number of Trust Units equal to the Exchange Ratio as at the last business

day prior to the day of closing of the purchase and sale of such Exchangeable Share under the Exchange Right (the “Exchange Price”).

If, as a result of solvency provisions of applicable law, Baytex is unable to redeem all of a holder’s Exchangeable Shares which such holder is entitled to have redeemed in accordance with the Exchangeable Share Provisions, the holder will be deemed to have exercised the Optional Exchange Right with respect to the unredeemed Exchangeable Shares and the Trust or ExchangeCo will be required to purchase such shares from the holder in the manner set forth above.

SUPPORT AGREEMENT

Under the Support Agreement, the Trust has agreed that:

(a) it will take all actions and do all things necessary to ensure that Baytex is able to pay to the holders of the Exchangeable Shares the Liquidation Amount in the event of a liquidation, dissolution or winding-up of Baytex, the Retraction Price in the event of the giving of a Retraction Request by a holder of Exchangeable Shares, or the Redemption Price in the event of a redemption of Exchangeable Shares by Baytex; and

(b) it will not vote or otherwise take any action or omit to take any action causing the liquidation, dissolution or winding-up of Baytex.

The Support Agreement also provides that the Trust will not issue or distribute to the holders of all or substantially all of the outstanding Trust Units:

(a) additional Trust Units or securities convertible into Trust Units;

(b) rights, options or warrants for the purchase of Trust Units; or

(c) units or securities of the Trust other than Trust Units, evidences of indebtedness of the Trust or other assets of the Trust;

unless the same or an equivalent distribution is made to holders of Exchangeable Shares, an equivalent change is made to the Exchangeable Shares, such issuance or distribution is made in connection with a distribution reinvestment plan instituted for holders of Trust Units or a unitholder rights protection plan approved for holders of Trust Units by the Board of Directors of Baytex or the approval of holders of Exchangeable Shares has been obtained.

In addition, the Trust may not subdivide, reduce, consolidate, reclassify or otherwise change the terms of the Trust Units unless an equivalent change is made to the Exchangeable Shares or the approval of the holders of Exchangeable Shares has been obtained.

In the event of any proposed take-over bid, issuer bid or similar transaction affecting the Trust Units, the Trust will use reasonable efforts to take all actions necessary or desirable to enable holders of Exchangeable Shares to participate in such transaction to the same extent and on an economically equivalent basis as the Trust Unitholders.

The Support Agreement also provides that, as long as any outstanding Exchangeable Shares are owned by any person or entity other than the Trust or any of its respective subsidiaries and other affiliates, the Trust will, unless approval to do otherwise is obtained from the holders of Exchangeable Shares, remain the direct or indirect beneficial owner collectively of more than 50% of all of the issued and outstanding voting securities of Baytex, provided that the Trust will not be in violation of this obligation if a party acquires all or substantially all of the assets of the Trust. With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making certain necessary amendments or curing ambiguities or clerical errors (in each case provided that the Board of Directors of Baytex and the Trustee are of the opinion that such amendments are not prejudicial to the interests of the holders of the Exchangeable Shares), the Support Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Under the Support Agreement, the Trust has agreed to not exercise any voting rights attached to the Exchangeable Shares owned by it or any of its respective subsidiaries and other affiliates on any matter considered at meetings of holders of Exchangeable Shares (including any approval sought from such holders in respect of matters arising under the Support Agreement).

Delivery of Trust Units

The Trust has also agreed to make such filings and seek such regulatory consents and approvals as are necessary so that the Trust Units issuable upon the exchange of Exchangeable Shares will be issued in compliance with applicable securities laws in Canada and may be traded freely on the TSX or such other exchange on which the Trust Units may be listed, quoted or posted for trading from time to time.

NOTES

The following summary of the material attributes and characteristics of the Notes which were issued pursuant to the Note Indenture between Baytex and Valiant Trust Company, as trustee (the "Note Trustee").

Terms and Issue of Notes

Pursuant to the Arrangement, Notes were issued to the Trust in return for Trust Units. The Notes are unsecured, payable on demand and bear interest from the date of issue at an interest rate equal to 12% per annum. Interest is payable for each month during the term on the 10th day of the month following such month.

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

In contemplation of the possibility that Notes may be distributed to Trust Unitholders upon the redemption of their Trust Units, the Note Indenture provides that if persons other than the Trust (the "Non-Fund Holders") own Notes having an aggregate principal amount in excess of $1,000,000, either the Trust or the Non-Fund Holders shall be entitled, among other things, to require the Note Trustee to exercise the powers and remedies available under the Note Indenture upon an event of default and, with the Trust, the Non-Fund Holders may provide consents, waivers or directions relating generally to the variance of the Note Indenture and the rights of noteholders. The Note Indenture allows the Trust flexibility to delay payments of interest or principal otherwise due to it while payment is made to other noteholders, and to allow other noteholders to be paid out before the Trust. Any delayed payments will be due 5 days after demand.

Principal and interest on the Notes are payable in lawful money of Canada directly to the holders of Notes at their address set forth in the register of holders of Notes. The Trust is the holder of all of the issued and outstanding Notes.

Ranking

The Notes are unsecured debt obligations of Baytex and rank *pari passu* with all other unsecured indebtedness of Baytex, but subordinate to all secured debt.

Events of Default

The Note Indenture provides that any of the following shall constitute an "Event of Default" under the Note Indenture: (i) default in payment of the principal of the Notes when required; (ii) the failure to pay all of the interest obligations on the Notes for a period of 90 days; (iii) if Baytex has defaulted and a demand for payment has been made under any material instrument, indenture or document evidencing indebtedness of more than $250 million and Baytex has failed to remedy such default within applicable curative periods; (iv) certain events of winding-up, liquidation, bankruptcy, insolvency, receivership or seizure; (v) default in the observance or performance of any other covenant or condition of the Note Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Note Trustee to Baytex specifying such default and requiring Baytex to rectify the same; (vi) Baytex ceasing to carry on its business other than as contemplated in this Information Circular; and (vii) material default by Baytex under material agreements if property having a fair market value in excess of $125 million is liable to forfeiture or termination.

NPI AGREEMENT

Coincident with the completion Arrangement becoming effective, Baytex and the Trust entered into the NPI Agreement, pursuant to which Baytex granted and set over to the Trust the right to receive certain payments (the "NPI") on petroleum and natural gas rights held by Baytex from time to time. As consideration for the granting of the NPI, in addition to all amounts previously paid by the Trust to Baytex, the Trust agreed to pay to Baytex an amount (the "Deferred Purchase Price Obligation") equal to: (a) the portion of acquisition costs ("Future Acquisition Costs") for petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by Baytex from time to time ("Property Interests") acquired after the date of the NPI Agreement which are attributable to "Canadian resource property" (as defined in the Tax Act) payable at the time of incurring such Future Acquisition Costs, plus (b) drilling, completion, equipping and other costs ("Capital Expenditures") in respect of the Property Interests payable at the time of incurring such Capital Expenditures, plus (c) the portion of indebtedness incurred in respect of such Future Acquisition Costs and Capital Expenditures payable at the time of satisfaction by Baytex of such indebtedness. In addition, the Trust will pay over to Baytex, to satisfy the Deferred Purchase Price Obligation, the net proceeds of any issue of Trust Units or the proceeds from the disposition of the NPI on any petroleum and natural gas rights held by Baytex. The Trust shall not be obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

Pursuant to the terms of the NPI Agreement, the Trust is entitled to a payment from Baytex for each month equal to the amount by which ninety-nine (99%) percent of the gross proceeds from the sale of production attributable to the Property Interests for such month (the "NPI Revenues") exceed ninety-nine (99%) percent of certain deductible costs for such period. Baytex may acquire and fund additional Property Interests from residual revenues, the Deferred Purchase Price Obligation, borrowings or from its working capital.

If Baytex wishes to dispose of any Property Interests which will result in proceeds in excess of a threshold amount, the Board of Directors of Baytex shall approve such disposition, however, if the asset value (calculated in accordance with the terms of the NPI Agreement) of any interests included in such disposition is greater than a threshold percentage of the asset value of all the Property Interests held by Baytex, such disposition must be approved by a Special Resolution of the Unitholders. The term of the NPI Agreement will be for so long as there are

petroleum and natural gas rights to which the NPI applies.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Annual Financial Information

The following is a summary of selected financial information of the Trust/Baytex for the periods indicated. Reference should be made to the audited consolidated financial statements of the Trust attached hereto as Appendix D.

	Year Ended December 31, 2003	Year Ended December 31, 2002	Year Ended December 31, 2001
	(thousands of dollars, except per unit amounts)		
Total revenue (before royalties)	351,404	365,860	329,700
Cash flow from operations	138,233	191,086	144,070
Per unit/share – basic	2.49	3.65	2.91
Per unit/share - fully diluted	2.45	3.59	2.87
Net income (loss)	38,138	45,136	(137,107)
Per unit/share – basic	0.69	0.86	(2.77)
Per unit/share - fully diluted	0.67	0.85	(2.77)
Total assets	959,136	997,760	967,046
Total long-term financial liabilities	232,562	326,977	330,102
Cash distributions per Trust Unit	0.60	—	—

Note:

(1) The reorganization of Baytex into an income trust structure occurred effective September 2, 2003.

Quarterly Financial Information

The following is a summary of selected financial information of the Trust/Baytex for the periods indicated.

	Total Revenues (Before Royalties)	Net Income (Loss)	Net Income (Loss) Per Unit/Share – Basic	Net Income (Loss) Per Unit/Share – Fully Diluted	Cash Flow From Operations	Cash Flow From Operations Per Unit/Share – Basic	Cash Flow From Operations Per Unit/Share – Fully Diluted
	(thousands of dollars, except per unit amounts)						
2003							
First Quarter	107,047	32,943	0.62	0.61	54,707	1.03	1.03
Second Quarter	79,288	41,830	0.78	0.76	33,372	0.62	0.61
Third Quarter	87,200	(45,516)	(0.83)	(0.83)	19,975	0.36	0.36
Fourth Quarter	77,869	8,881	0.15	0.15	30,179	0.51	0.51
2002							
First Quarter	79,130	7,304	0.14	0.14	40,125	0.77	0.76
Second Quarter	91,507	21,354	0.41	0.40	49,208	0.95	0.93
Third Quarter	94,663	3,687	0.07	0.07	48,637	0.93	0.91
Fourth Quarter	100,590	12,791	0.24	0.24	53,116	0.69	0.67

Cash Distributions

The Trust makes 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 of Baytex on behalf of the Trust reviews the 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. The current distribution policy targets the use of approximately 30% to 40% of cash available for distribution for capital expenditures. Depending upon commodity prices and the size of the capital budget, it is expected that 30% to 40% of the cash available for distribution will fund a portion of the Trust's annual capital expenditure program, including both exploitation expenditures and minor property acquisitions, but excluding major acquisitions.

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

The following is a summary of the distributions declared by Baytex from its inception in September of 2003 to March 31, 2004.

For the Month Ended	Distributions per Unit	Payment Date
September 30, 2003	$ 0.15	October 15, 2003
October 31, 2003	$ 0.15	November 17, 2003
November 30, 2003	$ 0.15	December 15, 2003
December 31, 2003	$ 0.15	January 15, 2004
January 31, 2004	$ 0.15	February 17, 2004
February 29, 2004	$ 0.15	March 15, 2004
March 31, 2004	$ 0.15	April 15, 2004

Total:	$	1.05

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of the financial conditions and results of operations of the Trust for the year ending December 31, 2003 are set forth in Appendix C attached hereto, and form, inclusive, of an integral part of this Renewal Annual Information Form.

MARKET FOR SECURITIES

The Trust Units are listed for trading on the TSX under the symbol "BTE.UN". The following table sets forth the high and low closing trading prices and the aggregate volume of trading of the Trust Units as reported by the TSX for the periods indicated. the Trust Units commenced trading on the TSX on September 8, 2003.

	Price Range		Volume Traded
	High ($)	Low ($)	
2003			
September	10.85	9.19	9,992,166
October	10.65	9.49	13,469,910
November	10.64	9.98	7,380,404
December	10.89	9.97	10,131,182
2004			
January	11.45	10.60	8,866,915
February	10.82	9.78	11,503,106
March	11.32	10.25	14,408,162

LEGAL PROCEEDINGS

There are no outstanding legal proceedings involving claims for damages, exclusive of interest and costs, in excess of ten percent (10%) of the current assets of the Trust, to which the Trust is a party or of which any of its Properties are subject, nor are there any such proceedings known to be contemplated.

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Trust, nominees for director, any Unitholder who beneficially owns more than 10% of the Trust Units or any known associate or affiliate of such persons in any transaction since the beginning of the Trust's last completed financial year or in any proposed transaction which has materially affected or would materially affect the Trust.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Trust are Deloitte & Touche LLP, Chartered Accountants, Calgary, Alberta.

Valiant Trust Company, at its principal office in Calgary, Alberta and through its co-agent, Equity Transfer Services Inc., at its principal office in Toronto, Ontario is the transfer agent and registrar for the Trust Units.

INDUSTRY CONDITIONS

General

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 agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, 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 the operations of the Trust 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 the Trust is 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 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. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. 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 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 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 exports for a term of less than 2 years or for a term of 2 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 the approval of the Governor in Council.

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

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

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. 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; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Provincial Royalties and Incentives

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 negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. 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 and the type or quality of the petroleum product produced.

From time to time 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 cash flow within the industry.

In the Province of Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m(3) and 25% at prices at and above $210 per m(3). The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Crude oil and natural gas royalty programs for specific wells and royalty reductions reduce the amount of Crown royalties paid by the Trust's operating subsidiaries to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

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 the Province of Alberta has been consolidated into the Alberta Environmental Protection and Enhancement Act (the "APEA"), which came into force on September 1, 1993. The APEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties. The Trust is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result

of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the APEA and similar legislation in other jurisdictions in which it operates. The Trust believes that it is in material compliance with applicable environmental laws and regulations. The Trust also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on the Trust cannot be determined at this time.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Baytex and the Trust. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Renewal Annual Information Form.

Dependence on Baytex

The Trust is an open-ended, limited purpose trust which will be entirely dependent upon the operations and assets of Baytex through its ownership of the common shares, the Notes and the NPI. Accordingly, the cash distributions to the Trust Unitholders will be dependent upon the ability of Baytex to meet its interest and principal repayment obligations under the Notes, to declare and pay dividends on the common shares, and to pay the NPI. Baytex's income will be received from the production of oil and natural gas from Baytex's existing Canadian resource Properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. Baytex is generally not involved in the exploration for oil and natural gas. As a result, if the oil and natural gas reserves associated with Baytex's Canadian 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 the Trust may be adversely affected.

Exploitation and Development

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which Baytex has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods, and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three-dimensional seismography, reservoir simulation studies and horizontal drilling have been used by Baytex and will be used by Baytex to improve its ability to find, develop and produce oil and natural gas.

Operations

Baytex's 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, blow-outs, craterings and fires, all of which could result in personal injuries, loss of life and damage to the property of Baytex and others. Baytex has both safety and environmental policies in place to protect its operators and employees, as well as to meet the regulatory requirements in those areas where it operates. In addition, Baytex has liability insurance policies in place, in such amounts as it considers adequate, however, it will not be fully insured against all of these risks, nor are all such risks insurable.

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. 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. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Baytex to certain Properties. A reduction of the income from the NPI could result in such circumstances.

Oil and Natural Gas Prices

The price of oil and natural gas will fluctuate and price and demand are factors beyond Baytex's control. Such fluctuations will have a positive or negative effect on the revenue to be received by it. Such fluctuations will also have an effect on the acquisition

costs of any future Oil and Natural Gas Properties that Baytex may acquire. As well, cash distributions from the Trust will be highly sensitive to the prevailing price of crude oil and natural gas.

Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Baytex will be affected by numerous factors beyond its control. These factors include demand for oil and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas.

Capital Investment

The timing and amount of capital expenditures will directly affect the amount of income for distribution to Trust Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

Debt Service

Baytex has credit facilities in the amount of $165 million. 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 any amounts to the Trust. Although it is believed that the bank line of credit is sufficient, there can be no assurance that the amount will be adequate for the financial obligations of Baytex or that additional funds can be obtained.

The lenders have been provided with security over substantially all of the assets of Baytex. If Baytex becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lenders may foreclose on or sell the Properties free from or together with the NPI.

Reserves

Although Sproule and Baytex have carefully prepared the reserve figures included herein 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. Probable reserves estimated for Properties may require revision based on the actual development strategies employed to prove such reserves. Declines in the reserves of Baytex which are not offset by the acquisition or development of additional reserves may reduce the underlying value of Trust Units to Trust Unitholders. Trust Units will have no value once all of the oil and natural gas reserves of Baytex have been produced. As a result, holders of Trust Units will have to obtain the return of capital invested out of cash flow derived from their investment in such Trust Units.

Competition

The industry is highly competitive in the acquisition of exploration prospects and the development of new sources of production and the sale of oil and natural gas.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders in respect of Baytex or the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Baytex. Although Baytex has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy its actual future environmental and reclamation obligations.

Delay in Cash Distributions

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 the Manager or Baytex, 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 the properties, or the establishment by the operator of reserves for such expenses.

Depletion of Reserves

The Trust has certain unique attributes that differentiate it from other oil and gas industry participants. Distributions of Distributable Income in respect of Properties, absent commodity price increases or cost effective acquisition and development activities will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Baytex will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, Baytex's initial production levels and reserves will decline.

Baytex's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on Baytex's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Baytex's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, Baytex's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that Baytex is required to use cash flow to finance capital expenditures or property acquisitions, the level of Distributable Income will be reduced.

There can be no assurance that Baytex will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Variations in Interest Rates and Foreign Exchange Rates

Variations in interest rates could result in a significant change in the amount the Trust pays to service debt, potentially impacting distributions to Unitholders.

In addition, the exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in the

receipt by the Trust of fewer Canadian dollars for its production which may affect future distributions. Baytex has initiated certain hedges to mitigate these risks. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Distributions

Historical distribution payments of the Trust may not be reflective of future distribution payments, which will be subject to review by the Board of Directors of Baytex taking into account the prevailing financial circumstances of Baytex at the relevant time. The actual amount distributed, if any, is dependent on the commodity price environment and is at the discretion of the Board of Directors.

Distributable cash available for distribution is not an earnings measure recognized by generally accepted accounting principles and is not necessarily comparable to the measurement of distributable cash available for distribution in other similar trust entities.

Mutual Fund Trust Status

It is intended that the Trust continue to qualify as a mutual fund trust for the purposes of the *Income Tax Act* (Canada) (the "Tax Act"). The Trust may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

Where at the end of any month a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP") or deferred profit sharing plan ("DPSP") (collectively, "Exempt Plans") holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI. 1 of the Tax Act

equal to 1 percent of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. An RRSP or RRIF holding Trust Units that are not qualified investments would become taxable on income attributable to the Trust Units while they are not qualified investments (including the entire amount of any capital gain arising on a disposition of the non-qualified investment). RESPs which hold Trust Units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency.

Trust Units would become foreign property for Exempt Plans upon the Trust ceasing to be a mutual fund trust.

The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalty held by the Trust. 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.

The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws.

Trust Units would become taxable Canadian property. As a result, non-resident Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

In addition, the Trust may take certain measures in the future to the extent the Trust believes such measures are necessary to ensure the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units.

Non-resident Ownership of Trust Units

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust must not be established or maintained primarily for the benefit of non-residents of Canada ("non-residents") within the meaning of the Tax Act. The Trust Indenture provides that if at any time the Trust or Baytex becomes aware that the beneficial owners of 50% or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trust, by or through Baytex on the Trust's behalf, shall take such action as may be necessary to carry out the foregoing intention.

Income Tax Matters

Generally, oil and gas income trusts including this income trust 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 interest expense and other deductions. If such a challenge were to succeed against the Trust, it could materially adversely affect the amount of distributions available to the Trust. The Trust and Baytex believe that the interest expense inherent in the structure of the Trust is supportable and reasonable in light of the terms of the Notes.

Nature of Trust Units

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 the Trust. 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 Trust's primary assets will be the Notes, common shares, the NPI and other investments in securities. The price per Trust Unit is a function of anticipated Distributable Income, the Properties acquired by Baytex, and Baytex's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire Oil and Natural Gas Properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

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, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Redemption Right

It is anticipated that the redemption right will not be the primary mechanism for Trust Unitholders to liquidate their investments. Notes or Redemption Notes which may be distributed *in specie* to Trust Unitholders in connection with a redemption will not be listed on any stock exchange and no established market is expected to develop for such Notes or Redemption Notes. Cash redemptions are subject to limitations. See "*Additional Information Respecting Baytex Energy Trust - - Redemption Right*".

Unitholder Limited Liability

The Trust Indenture provides that no Trust Unitholder will be subject to any liability in connection with the Trust or its affairs or obligations and, in the event that a court determines that Trust Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, the Unitholder's share of the Trust's assets.

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 the Trust 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 operations of the Trust 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 the Trust Unitholders for claims against the Trust.

Permitted Investments

An investment in the Trust should be made with the understanding that the value of any Permitted Investments may fluctuate in accordance with changes in the financial condition of the issuers of the Permitted 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. Other Permitted 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 Permitted Investments.

Regulatory Matters

The Corporation's operations are subject to a variety of federal and provincial laws and regulations, including laws and regulations relating to the protection of the environment.

Kyoto Protocol

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol which will require, upon ratification, nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Government of Canada ratified and signed the Kyoto Protocol. As a result of the ratification of the Kyoto Protocol and the adoption of legislation or other regulatory initiatives designed to implement its objectives by the federal or provincial governments, reductions in greenhouse gases from crude oil and natural gas producers may be required which could result in, among other things, increased operating and capital expenditures for those producers (including the Trust) which may make certain production of crude oil and natural gas by those producers uneconomic resulting in reductions in such production. Until such legislation or other regulatory initiatives are finalized, the impact of the Kyoto Protocol and any such legislation adopted as a result of its ratification remains uncertain.

Conflicts of Interest

The directors and officers of Baytex 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, the directors and officers of the Corporation may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at the date hereof, neither the Trust nor Baytex is aware of any existing or potential material conflicts of interest between the Trust and Baytex and a director or officer of Baytex.

ADDITIONAL INFORMATION

Additional information relating to the Trust may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and interests of insiders in material transactions, where applicable, is contained in the Information Circular of the Trust dated April 12, 1004, 2004. Additional financial information is provided in the Trust's financial statements for the year ended December 31, 2003 which are attached hereto as Appendix D.

The Trust shall provide to any person, upon request to the Chief Financial Officer of the Corporation:

1. when the securities of the Trust are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:

   (a) one copy of the Annual Information Form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

   (b) one copy of the comparative financial statements of the Trust for its most recently completed fiscal period for which financial statements have been filed, together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Trust that have been filed, if any, for any period after the end of its most recently completed financial year;

   (c) one copy of the Information Circular of the Trust in respect of its most recent annual and special meeting of Unitholders; and

   (d) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and which are not required to be provided under items (a) to (c) above; or

2. at any other time, one copy of any documents referred to in items (1)(a), (b) and (c) above, provided that the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Baytex Energy Trust
2200, 205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845
www.baytex.ab.ca

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Baytex, on behalf of the Trust, are responsible for the preparation and disclosure of information with respect to the oil and gas activities of Baytex in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

(b) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004 using constant prices and costs; and

   (ii) the related estimated future net revenue.

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 the Baytex, on behalf of the Trust, has

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

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

(b) the filing of the report 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.

(signed) "*Raymond T. Chan*"

Raymond T. Chan
President and Chief Executive Officer

(signed) "*Daniel G. Belot*"

Daniel G. Belot
Vice President, Finance and Chief Financial Officer

(signed) "*Dale O. Shwed*""
Dale O. Shwed
Director

(signed) "*John A. Brussa*"
John A. Brussa
Director

March 23, 2004

APPENDIX B

REPORT ON RESERVES DATA

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

1. We have evaluated the reserves data of the Trust as at January 1, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas and proved plus probable reserves estimated as at January 1, 2004 using constant prices and costs; and

   (ii) the related estimated future net revenue.

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, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to Baytex's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of [Audit/ Evaluation/ Review] Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($Million)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	March 23, 2004	Canada	—	733.4	—	733.4

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

(signed) "Sproule Associates Limited"
Calgary, Alberta
March 23, 2004

APPENDIX C

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis, dated March 5, 2004, should be read in conjunction with Baytex Energy Trust's (the "Trust") audited consolidated financial statements for the fiscal years ended December 31, 2003 and 2002. Per 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.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations is not a measure based on generally accepted accounting principles ("GAAP"), but is a financial term commonly used in the oil and gas industry. It represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. 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.

2003 OVERVIEW

The Trust was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of its producing and exploratory petroleum and natural gas assets. As Crew was a related party at the effective date of the Plan of Arrangement, the assets and liabilities were transferred at book value. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. The Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company, its subsidiaries and partnership. After giving effect to the Plan of

Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to Baytex Energy Ltd. 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.

Production

The Trust's average production for fiscal 2003 decreased by six percent to 36,686 boe per day from 39,214 boe per day for fiscal 2002. This decrease was the result of property dispositions that occurred at the end of the first quarter of 2003 and the transfer of the petroleum and natural gas assets to Crew under the Plan of Arrangement effective September 2, 2003.

Light oil production decreased 28 percent to 2,273 barrels per day during 2003 from 3,154 barrels per day in 2002. Heavy oil production during 2003 was 23,911 barrels per day, consistent with production of 23,967 barrels per day during fiscal 2002. Natural gas production for 2003 decreased by 13 percent to 63.0 million cubic feet per day compared to 72.6 million cubic feet per day for the prior year.

Production by Area

	Light Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2003				
Heavy Oil District	**—**	**23,911**	**10.6**	**25,676**
Conventional Oil and Gas District	**2,273**	**—**	**52.4**	**11,010**
Total Production	**2,273**	**23,911**	**63.0**	**36,686**
2002				
Heavy Oil District	—	23,967	10.5	25,710
Conventional Oil and Gas District	3,154	—	62.1	13,504
Total Production	3,154	23,967	72.6	39,214

Revenue

Petroleum and natural gas sales for 2003 decreased by four percent to $351.4 million from $365.9 million for fiscal 2002. Benchmark WTI crude oil averaged US$31.04 per barrel for 2003, representing a 19 percent increase over the US$26.08 per barrel for 2002. Correspondingly, the Trust's light oil and NGLs price increased to $39.04 per barrel from $33.86 per barrel in 2002. The heavy oil price decreased five percent to $25.12 per barrel in 2003 from $26.39 per barrel in 2002, principally due to the increase in heavy oil differentials. Natural gas prices were 54 percent higher in 2003, averaging $6.07 per thousand cubic feet compared to $3.94 per thousand cubic feet during the previous year. Overall, after accounting for financial derivative contracts, the Trust averaged $26.72 per boe for 2003, a 4 percent increase from $25.56 per boe received in the prior year. For the per– sales-unit calculations, heavy oil sales for 2003 were 650 barrels per day lower than the production for the year due to inventory in transit under the Frontier supply agreement.

For 2003, light oil revenue decreased 17 percent over 2002, as the 15 percent increase in wellhead prices was offset by a 28 percent decrease in production. Revenue from heavy oil

decreased eight percent due to a five percent decrease in wellhead prices and a three percent decrease in sales volumes. Natural gas revenue increased 34 percent as the 13 percent production decrease was offset by a 54 percent increase in wellhead prices.

Royalties

For the year ended December 31, 2003, royalties increased 14 percent to $67.2 million from $58.9 million last year and were 17.4 percent of sales compared to 15.7 percent of sales in 2002. Higher realized gas prices resulted in higher royalty rates. Royalties for 2003 were 17.8 percent of sales for light oil, 13.8 percent for heavy oil and 22.9 percent for natural gas. These rates compared to 16.7 percent, 13.9 percent and 19.5 percent, respectively, for 2002.

Operating Expenses

Operating expenses for 2003 increased 14 percent to $86.0 million from $75.2 million for 2002. This increase is attributable to the disposition of properties with lower operating costs and a general increase in field operating costs. Operating expenses were $6.54 per boe for 2003 compared to $5.26 per boe for the prior year. Operating expenses were $8.32 per barrel of light oil, $7.34 per barrel of heavy oil and $0.73 per thousand cubic feet of natural gas for 2003 versus $5.83, $5.99 and $0.61, respectively, for 2002.

Gross Revenue Analysis

	2003		2002	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Light oil	**32,393**	**39.04**	38,985	33.86
Heavy oil	**213,297**	**25.12**	230,874	26.39
Derivative contract loss	**(33,777)**	**(3.62)**	(10,622)	(1.07)
Total oil revenue	**211,913**	**22.74**	259,237	26.19
Natural gas revenue	**139,491**	**6.07**	104,284	3.94
Derivative contract gain	**—**	**—**	2,339	0.09
Total natural gas revenue	**139,491**	**6.07**	106,623	4.03
Total revenue (boe @ 6:1)	**351,404**	**26.72**	365,860	25.56

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/mcf.

Operating Netback

	Light Oil & NGLs ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGLs ($/bbl)		Natural Gas ($/mcf)		BOE ($/boe)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Sales price	**39.04**	33.86	**25.12**	26.39	**26.36**	27.26	**6.07**	3.94	**29.28**	26.14
Royalties	**(6.96)**	(5.67)	**(3.47)**	(3.66)	**(3.78)**	(3.89)	**(1.39)**	(0.77)	**(5.11)**	(4.12)
Operating costs	**(8.32)**	(5.83)	**(7.34)**	(5.99)	**(7.43)**	(5.97)	**(0.73)**	(0.61)	**(6.54)**	(5.26)
Operating netback	**23.76**	22.36	**14.31**	16.74	**15.15**	17.40	**3.95**	2.56	**17.63**	16.76

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

General and administrative expenses for 2003 were $8.9 million, compared to $6.7 million a year ago. On a sales-unit basis, these expenses increased to $0.67 per boe from $0.47 per boe. In accordance with the full-cost accounting policy, $4.4 million of expenses were capitalized in 2003, compared with $6.7 million capitalized in 2002. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation

The Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003.

Compensation expense was also calculated on the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as compensation expense for all stock options granted on or after January 1, 2003. All outstanding stock options were cancelled or exercised effective September 2, 2003.

Interest Expense

For 2003, interest expenses on long-term debt were $23.5 million compared to $25.2 million for 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S.dollar based interest expenses.

Costs on Redemption and Exchange of Notes

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 million of 9.625 percent senior subordinated notes due 2010 in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is $4.7 million of costs on the redemption of the US$57 million senior 7.23 percent secured notes.

Depletion and Depreciation

Depletion and depreciation increased to $116.3 million for 2003 compared to $106.8 million last year. On a sales-unit basis, the provision for 2003 was $8.69 per boe compared to $7.46 per boe for 2002 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument 51-101 ("NI 51-101"), as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

General and Administrative Expenses

($ thousands)	2003	2002
Gross corporate expense	**$ 20,496**	$ 19,328
Operator's recoveries	**(7,166)**	(5,842)
Subtotal	**13,330**	13,486
Full-cost accounting capitalization	**(4,403)**	(6,743)
Net expense	**$ 8,927**	$ 6,743

The ceiling test was calculated at December 31, 2003 using the proved reserves as determined under NI 51-101 and at prices at year-end. No write-down was required at December 31, 2003 under this calculation.

Site Restoration Costs

Site restoration costs for the year ended December 31, 2003 increased to $2.9 million from $2.8 million last year. On a sales-unit basis, the provision for 2003 was $0.22 per boe compared to $0.20 per boe for 2002 due to the changes in the proved reserves used in the calculation.

Foreign Exchange

Foreign exchange gain for 2003 was $52.1 million compared to $2.7 million in 2002. The 2003 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002. The 2002 gain is based on translation at 0.6331 at December 31, 2002 compared to 0.6279 at December 31, 2001.

Income Taxes

Current tax expenses were $9.7 million for 2003 compared to $9.7 million last year. The 2003 current tax expense is comprised of $8.0 million of Saskatchewan Capital Tax and $1.7 million of Large Corporation Tax compared to $8.1 million and $1.6 million, respectively, in 2002.

The fiscal 2003 provision for future income taxes was a recovery of $13.6 million compared to $37.9 million for the prior year. The future income tax recovery for 2003 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income. The federal resource tax changes include a change in the federal income tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. These changes are considered substantially enacted for the purposes of GAAP and the Company's future income tax liability has been reduced accordingly.

Canadian Tax Pools

($ thousands)	December 31, 2003
Cumulative Canadian exploration expense	**9,000**
Cumulative Canadian development expense	**63,000**
Cumulative Canadian oil and gas property expense	**96,000**
Undepreciated capital cost	**148,000**
Other	**48,000**
Total tax pools	**364,000**

Cash Flow from Operations

Cash flow from operations for the year ended December 31, 2003 decreased 28 percent to $138.2 million from $191.1 million for the previous year due to higher costs related to derivative contracts and reorganization under the Plan of Arrangement. On a barrel of oil equivalent basis, cash flow from operations was $10.51 for 2003 compared to $13.35 for 2002.

Capital Expenditures

Exploration and development expenditures increased to $180.1 million for 2003 compared to $136.3 million last year. Total capital expenditures for the last two years are summarized in the table below.

Liquidity and Capital Resources

At December 31, 2003, total net debt (including working capital) was $213.6 million compared to $362.8 million at December 31, 2002. The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from assets sales at the end of March 2003, and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

The Company's debt structure consists of two components. The first component is the senior credit facilities. On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. The credit

Cash Flow

	2003		2002	
	$/boe	Percent	$/boe	Percent
Production revenue	**29.28**	**100**	26.14	100
Derivative contract loss	**(2.57)**	**(9)**	(0.57)	(2)
Royalties	**(5.11)**	**(17)**	(4.12)	(16)
Operating expenses	**(6.54)**	**(22)**	(5.26)	(20)
Operating netback	**15.06**	**52**	16.19	62
General and administrative expenses	**(0.68)**	**(2)**	(0.47)	(2)
Reorganization costs	**(1.43)**	**(5)**	—	—
Interest expense	**(1.71)**	**(6)**	(1.69)	(6)
Current income taxes	**(0.73)**	**(3)**	(0.68)	(3)
Cash flow	**10.51**	**36**	13.35	51

Capital Expenditures

($ thousands)	2003	2002
Land	**$ 14,138**	$ 13,834
Seismic	**5,436**	8,183
Drilling and completion	**111,772**	81,862
Equipment	**42,365**	24,507
Other	**6,401**	7,949
Total exploration and development	**180,112**	136,335
Property acquisitions	**6,644**	45,713
Property dispositions	**(137,493)**	(55,580)
Net capital expenditures	**$ 49,263**	$ 126,468

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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. The facilities aggregating $165 million are subject to semi-annual reviews beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank credit facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of $65 million.

At December 31, 2003, there were 3.7 million exchangeable shares outstanding. The exchange ratio of these shares was 1.04530 trust units per exchangeable share at year-end. During 2003, a total of 1.0 million exchangeable shares were exchanged for trust units.

Cash Distributions

Total cash distributions of $0.60 per unit were declared from September to December 2003. During the first quarter of 2004, the monthly cash distribution of $0.15 per unit is estimated to be within the Trust's target distribution range of between 60 percent and 70 percent of cash flow.

Off-Balance Sheet Arrangements and Contractual Obligations

The Trust uses various financial derivative instruments, the fair values of which are not reflected on the consolidated balance sheet, to reduce

exposure to commodity and currency fluctuations. These risks, and the Trust's risk management policy, are discussed in "Risk and Risk Management." The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

The Trust has ongoing obligations related to abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Risk 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, revenue and cash flow depends on its success not only in 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

Contractual Obligations

		Payments Due by Period			
($ thousands)	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Long-term debt(1)	232,562	—	—	—	232,562
Operating leases	1,660	1,328	332	—	—
Transportation agreements	7,295	3,192	3,299	804	—
Total contractual obligations	241,517	4,520	3,631	804	232,562

(1) Total US $179.9 million

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 Evaluation Committee, consisting of qualified members of the Company's Board, of the Board of Directors 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 reserve estimates. Any future significant reserve 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 can be managed 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 of Directors. 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 recognizes gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

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 generally 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 denominated long-term debt. 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.

The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

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. These critical estimates are discussed below.

Oil And Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. Unit-of-production calculations are also used in the determination of the site restoration expense. By their inclusion in the unit-of-production calculation, reserve

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estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation and site restoration expense.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The ceiling test calculation utilizes and holds constant the prices and costs in effect at the end of the period. An estimate is made of the ultimate recoverable amount from future net revenue using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. The calculation of future net revenue in the ceiling test can be significantly impacted by fluctuations in any of these estimates. An impairment loss is recognized if the amount calculated under the ceiling test is less than the carrying costs of the Trust's petroleum and natural gas assets and can result in a significant accounting loss for a particular period.

New Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective to continue accrual accounting for positions hedged with derivatives. The new guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust is evaluating the impact that the adoption of AcG-13 will have on its results of operations.

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments," pursuant to the transitional provisions contained therein. Under this amended standard, the Trust is required to account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma

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earnings impact of related stock-based compensation expense is disclosed in note 10 of the consolidated financial statements.

In March 2003, the CICA issued Section 3110, "Asset Retirement Obligations." This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair 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 new standard is effective for all fiscal years beginning on or after January 1, 2004. The impact of adoption of this standard is estimated to be an increase in asset retirement obligation on the balance sheet of $33 million at December 31, 2003.

In February 2003, the CICA issued Accounting Guideline 14, "Disclosure of Guarantees" ("AcG-14"). AcG-14 establishes the disclosures required for obligations under certain guarantees. The disclosure requirements are effective for interim and annual periods beginning on or after January 1, 2003 and have been made in note 16 of the consolidated financial statements.

In 2003, the CICA issued Accounting Guideline 16, "Oil and Gas Accounting – Full-Cost" ("AcG-16"). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline proposes amendments to the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves 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 carrying amount 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. The adoption of this new guideline on January 1, 2004 is not anticipated to have an impact on the financial results of the Trust.

On November 10, 2003, the CICA issued a draft EIC (D37) on "Income Trusts - Exchangeable Units." The EIC proposes that the retained

interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from unitholder's equity. This draft EIC is currently under review and was not enacted in final form as of the time of release of the Trust's 2003 consolidated financial statements.

In June 2003, the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities," which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the consolidated financial statements of the Trust.

FOURTH QUARTER 2003

The following discussion reviews the Trust's results of operations for the fourth quarter of 2003.

Total production for the fourth quarter of 2003 decreased nine percent to 36,195 boe per day from 39,890 boe per day for the same period in 2002, due to the sale of properties in March 2003 in the Ferrier area and the transfer of properties

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to Crew in September 2003. Petroleum and natural gas sales decreased 23 percent to $77.9 million for the fourth quarter of 2003 from $100.6 million for the fourth quarter of 2002. Total royalties decreased 19 percent to $13.5 million for the fourth quarter of 2003 from $16.7 million for the same period in 2002. Operating expenses for the fourth quarter of 2003 increased 11 percent to $22.1 million from $19.8 million for the corresponding quarter in 2002. Operating expenses were $6.74 per boe for the fourth quarter of 2003 compared to $5.40 per boe for the fourth quarter of 2002.

General and administrative expenses for the fourth quarter of 2003 were $3.6 million compared to $1.6 million in 2002. On a per-sales-unit basis, these expenses were $1.07 per boe compared to $0.44 per boe as no expenses were capitalized in the fourth quarter of 2003 due to lower exploration activity since the effective date of the Plan of Arrangement.

Interest expenses on long-term notes and bank debt were $5.2 million for the fourth quarter of 2003, down from $7.2 million in the same quarter of 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

The foreign exchange gain in the fourth quarter of 2003 was $10.4 million compared to a gain of $1.3 million in the same period in 2002.

The provision for depletion and depreciation increased to $40.4 million for the fourth quarter of 2003 compared to $27.1 million for the same quarter of 2002. On a per-sales-unit basis, the provision for the current quarter was $12.14 per boe compared to $7.39 per boe for the same quarter in 2002, due to the revision in proved reserves under the new standards of disclosure for oil and gas activities, NI 51-101, as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Net income for the fourth quarter of 2003 was $8.9 million compared to $12.8 million for the corresponding quarter of 2002. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

Outstanding Unit Information

At of February 29, 2004, the Trust had 61,027,681 units and 3,530,506 exchangeable shares outstanding. The exchange ratio at February 29, 2004 was 1.07444 trust units per exchangeable share.

Selected Annual Financial Information

($ thousands, except per-unit amounts)	2003	2002	2001
Revenue	**$ 351,404**	$ 365,860	$ 329,700
Net income (loss)	**38,138**	45,136	(137,107)
Per-unit basic	**0.69**	0.86	(2.77)
Per-unit diluted	**0.67**	0.85	(2.77)
Total assets	**959,136**	997,760	967,046
Total long-term financial liabilities	**232,562**	326,977	330,102
Cash distributions declared(1)	**$ 0.60**	$ —	$ —

(1) Total unit distributions declared since September 2, 2003.

Overall production for 2003 was 36,686 boe per day which represented a six percent decrease from 39,214 boe per day in 2002. Average wellhead prices received during 2003 were $29.28 per boe compared to $26.14 during 2002. Production in 2001 was 43,488 boe per day. Average wellhead prices received in 2001 were $21.37 per boe. Total revenue for 2003 was $351.4 million compared to $365.9 million in 2002 and $329.7 million in 2001.

Due to wide heavy oil differentials at year-end 2001, the Trust incurred a $131.3 million ceiling test write-down (net of $103.2 million of future income taxes). This amount was recognized as additional depletion and depreciation for the year ended December 31, 2001.

The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from asset sales at the end of March 2003 and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

Quarterly Financial Information (unaudited)

($ thousands, except per-unit amounts)	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2	2002 Q1
Revenue	**77,869**	**87,200**	**79,288**	**107,047**	100,590	94,633	91,507	79,130
Cash flow from operations	**30,179**	**19,975**	**33,372**	**54,707**	53,116	48,637	49,208	40,125
Per unit basic	**0.51**	**0.36**	**0.62**	**1.03**	0.69	0.93	0.95	0.77
Per unit diluted	**0.51**	**0.36**	**0.61**	**1.01**	0.67	0.91	0.93	0.76
Net income (loss)	**8,881**	**(45,516)**	**41,830**	**32,943**	12,791	3,687	21,354	7,304
Per unit basic	**0.15**	**(0.83)**	**0.78**	**0.62**	0.24	0.07	0.41	0.14
Per unit diluted	**0.15**	**(0.83)**	**0.76**	**0.61**	0.24	0.07	0.40	0.14
Production								
Light oil and NGLs (bbls/d)	**1,982**	**1,989**	**2,167**	**2,969**	2,909	2,999	2,904	3,818
Heavy oil (bbls/d)	**24,400**	**25,123**	**22,816**	**23,278**	25,009	23,504	24,498	22,838
Total oil and NGLs (bbls/d)	**26,382**	**27,112**	**24,983**	**26,247**	27,918	26,503	27,402	26,656
Natural gas (mmcf/d)	**58.9**	**61.8**	**57.5**	**74.0**	71.8	71.3	73.3	73.7
Barrels of oil equivalent (boe/d @ 6:1)	**36,195**	**37,412**	**34,574**	**38,580**	39,890	38,391	39,625	38,948
Average Prices								
WTI oil (US$/bbl)	**31.18**	**20.20**	**28.91**	**33.86**	28.15	28.27	26.25	21.64
Edmonton par oil ($/bbl)	**39.56**	**40.94**	**41.08**	**50.91**	42.81	44.02	40.40	33.51
BTE light oil ($/bbl)	**36.41**	**34.43**	**37.13**	**45.41**	37.67	37.36	34.53	27.58
BTE heavy oil ($/bbl)	**22.40**	**24.19**	**22.98**	**31.48**	26.09	31.03	26.64	21.58
BTE total oil ($/bbl)	**23.48**	**24.92**	**24.24**	**33.15**	37.30	31.75	27.47	22.44
BTE natural gas ($/mcf)	**5.37**	**5.62**	**6.05**	**7.02**	5.29	3.33	3.94	3.19
BTE oil equivalent ($/boe)	**25.90**	**27.36**	**27.63**	**36.14**	28.64	28.10	26.29	21.39

APPENDIX D

FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

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 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 auditors 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.

(signed) "Raymond T. Chan"

Raymond T. Chan, CA
President and Chief Executive Officer
Baytex Energy Ltd.
March 5, 2004

(signed) "Daniel G. Belot"

Daniel G. Belot
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

AUDITORS' REPORT

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31,2003 and 2002 and the consolidated statements of operations and accumulated income (deficit) and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31,2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 5, 2004, we reported separately to the Trustee and Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 17, United States Accounting Principles and Reporting.

(signed)"Deloitte & Touche LLP"

Calgary, Alberta
March 5,2004

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands)	2003	2002
Assets		
Current assets		
Cash and short-term investments	**$ 53,731**	$ 4,098
Accounts receivable	**48,608**	52,667
Crude oil inventory	**5,900**	—
	108,239	56,765
Deferred charges and other assets	**7,764**	8,679
Petroleum and natural gas properties *(note 5)*	**843,133**	932,316
	$ 959,136	$ 997,760
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 80,126**	$ 92,563
Distributions payable to unitholders	**9,123**	—
	89,249	92,563
Long-term debt *(note 7)*	**232,562**	326,977
Deferred credits *(note 8)*	**—**	12,181
Provision for future site restoration costs	**23,483**	21,950
Future income taxes *(note 12)*	**174,385**	184,402
	519,679	638,073
Commitments and contingencies *(note 16)*		
Unitholders' Equity		
Unitholders'capital *(note 9)*	**446,594**	398,176
Exchangeable shares *(note 9)*	**26,372**	—
Contributed surplus *(note 10)*	**224**	—
Accumulated distributions	**(33,382)**	—
Accumulated deficit	**(351)**	(38,489)
	439,457	359,687
	$ 959,136	$ 997,760

See accompanying notes to the consolidated financial statements.

On behalf of the Board

(signed) "Naveen Dargan""

Naveen Dargan
Director
Baytex Energy Ltd.

(signed) "W.A. Blake Casidy"

W.A.Blake Cassidy
Director
Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED DEFICIT

Years Ended December 31 (thousands, except per-unit data)	2003	2002
Revenue		
Petroleum and natural gas sales	**$ 351,404**	$ 365,860
Royalties	**(67,175)**	(58,922)
	284,229	306,938
Expenses		
Operating	**86,034**	75,228
General and administrative	**8,927**	6,743
Unit-based compensation *(note 10)*	**739**	—
Interest *(note 7)*	**23,548**	25,217
Costs on redemption and exchange of notes *(note 7)*	**44,771**	—
Foreign exchange gain *(note 7)*	**(52,101)**	(2,691)
Depletion and depreciation	**116,317**	106,834
Site restoration costs	**2,973**	2,799
Reorganization costs *(note 4)*	**18,851**	—
	250,059	214,130
Income before income taxes	**34,170**	92,808
Income taxes (recovery) *(note 12)*		
Current	**9,663**	9,716
Future	**(13,631)**	37,956
	(3,968)	47,672
Net income	**38,138**	45,136
Deficit, beginning of year, as previously reported	**(38,489)**	(75,954)
Accounting policy change for foreign exchange *(note 3)*	**—**	(7,671)
Deficit, beginning of year, as restated	**(38,489)**	(83,625)
Accumulated deficit, end of year	**$ (351)**	$ (38,489)
Net income per trust unit *(note 11)*		
Basic	**$ 0.69**	$ 0.86
Diluted	**$ 0.67**	$ 0.85

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (thousands)	2003	2002
Cash provided by (used in):		
Operating activities		
Net income	**$ 38,138**	$ 45,136
Items not affecting cash:		
Unit-based compensation *(note 10)*	**739**	—
Amortization of deferred charges	**1,027**	1,052
Costs on redemption and exchange of notes *(note 7)*	**44,771**	—
Foreign exchange gain	**(52,101)**	(2,691)
Depletion and depreciation	**116,317**	106,834
Site restoration costs	**2,973**	2,799
Future income taxes (recovery)	**(13,631)**	37,956
Cash flow from operations	**138,233**	191,086
Change in non-cash working capital *(note 13)*	**(8,060)**	1,272
(Increase) decrease in deferred charges and other assets	**211**	(1,057)
Decrease in deferred credits	**(2,213)**	(18,694)
	128,171	172,607
Financing activities		
Redemption of senior secured notes *(note 7)*	**(89,950)**	—
Decrease in bank loan and other debt	**—**	(76,254)
Increase in deferred charges and other assets	**(7,425)**	—

Increase in deferred credits	**—**	12,181
Issue of trust units *(note 9)*	**61,525**	—
Payments of distributions	**(24,259)**	—
Issue of common shares *(note 9)*	**37,049**	3,497
Repurchase of common shares	**—**	(55)
	(23,060)	(60,631)
Investing activities		
Petroleum and natural gas property expenditures	**(186,756)**	(182,048)
Disposal of petroleum and natural gas properties	**137,493**	55,580
Properties held for sale	**—**	(46,895)
Change in non-cash working capital *(note 13)*	**(6,215)**	65,485
	(55,478)	(107,878)
Change in cash and short-term investments during the year	**49,633**	4,098
Cash and short-term investments, beginning of year	**4,098**	—
Cash and short-term investments, end of year	**$ 53,731**	$ 4,098

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2003 and 2002 *(all tabular amounts in thousands, except per unit amounts)*

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of the producing and exploratory oil and natural gas assets. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a wholly owned subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. 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 as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

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 revenues 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 reserve 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.

Cash and Short-term Investments

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

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 in one Canadian cost centre 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 gross proved petroleum and natural gas reserves. 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 (the “ceiling test”). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes, using period end prices and costs. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for Future Site Restoration Costs

Estimates are made of the future site restoration costs relating to the Trust’s petroleum and natural gas properties at the end of their economic life, based on year-end values, in accordance with current legislative requirements and industry practice. Annual charges are provided on a unit-of-production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

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

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.

Deferred Charges and Other Assets

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

Financial Instruments

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 policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use derivative financial instruments for trading or speculative purposes. Gains and losses on derivative contracts are recognized in income based on the underlying financial instrument or the future petroleum and natural gas production in the same period that the transactions are settled. The fair values of derivative instruments are not recorded in the consolidated balance sheet.

Gains and losses related to derivative financial instruments that have been closed prior to the end of the term are deferred and recognized in the consolidated statement of operations over the original term of the instrument.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Flow-through Shares

The Company had financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company records

the gross carrying value of the expenditures and records a future tax liability for the tax benefits renounced to subscribers.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 10. The exercise price of the rights granted under the plan may be reduced in future periods in accordance with the terms of the plan. Therefore, it is not possible to determine a fair value for the rights granted under the plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the consolidated financial statements for unexercised rights.

Compensation expense associated with rights granted under the plan is recognized in earnings over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in income in the period of change with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units, including exchangeable shares, outstanding during the year. Diluted per-unit amounts reflect the potential dilution that could occur if trust unit rights were exercised. 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 are assumed to be used to purchase trust units at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

Unit-based Compensation Plan

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, “Stock-based Compensation and Other Stock-based Payments”pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as non cash general and administrative expense for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (see note 10).

Foreign Currency

Effective January 1, 2002, the Company retroactively adopted the CICA amended accounting standard with respect to accounting for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on the year ended December 31, 2002 was to increase net income by $1.8 million. The effect of this change on the December 31, 2001 Consolidated Balance Sheet is an elimination of the unrealized foreign exchange loss of $13.7 million, a decrease in future income taxes of $6.0 million, and an increase in the deficit of $7.7 million.

4. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement (note 1), the Company transferred to Crew a portion of the Company’s producing and exploratory petroleum and natural gas assets. As this was a related party transaction, assets and liabilities were transferred at carrying value as follows:

Petroleum and natural gas assets and equipment	$ 21,244
Future income tax asset	3,278
Total assets transferred	24,522
Provision for future site restoration	(559)
Net assets transferred and reduction in share capital *(note 9)*	$ 23,963

Reorganization costs of $18.9 million were expensed in the consolidated statement of operations as a result of the Plan of Arrangement.

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5. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31	2003	2002
Petroleum and natural gas properties	**$ 2,016,382**	$ 1,989,246
Accumulated depletion and depreciation	**(1,173,249)**	(1,056,930)
	$ 843,133	$ 932,316

During 2003, $4.4 million (2002 – $6.7 million) of corporate expenses relating to exploration and development activities were capitalized. No corporate expenses have been capitalized since the inception of operations as a trust effective September 2, 2003. In calculating the depletion and depreciation provision for 2003, $51.1 million (2002 – $80.3 million) of costs relating to undeveloped properties and materials and supplies of $4.0 million (2002 – $5.5 million) were excluded from costs subject to depletion and depreciation.

6. BANK CREDIT FACILITIES

On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. 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. The facilities aggregating $165 million are subject to semi-annual review beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

7. LONG-TERM DEBT

As at December 31	2003	2002
Senior secured notes (2002 – US$57,000,000)	**$ —**	$ 90,037
10.5% senior subordinated notes (2003 – US$247,000; 2002 – US$150,000,000)	**319**	236,940
9.625% senior subordinated notes (2003 – US$179,699,000)	**232,243**	—
	$ 232,562	$ 326,977

Senior Secured Notes

On November 13, 1998, the Company issued US$57 million of senior secured notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of $90 million, resulting in a cost of $4.7 million on the redemption. Foreign exchange gains were included in income until the redemption of the notes.

Senior Subordinated Notes

On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

Interest Expense

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

	2003	2002
Bank loan	**$ 675**	$ 760
Amortization of deferred charges	**1,027**	1,052
Long-term debt	**21,846**	23,405
Total interest	**$ 23,548**	$ 25,217

8. DEFERRED CREDITS

As at December 31	2003	2002
Deferred interest swap settlement	**$ —**	$ 12,181

In August 2002, the Company terminated all outstanding interest rate swap agreements for total proceeds of $14.1 million. This amount was deferred and was being amortized as a reduction of interest expense over the original terms of the agreements. The amortization was terminated when the senior secured notes were redeemed and when the exchange offer related to the Old Notes was concluded (note 7). The residual balance was included in the cost on redemption and exchange of notes.

9. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Trust Units

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement,53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company.

On December 12,2003, the Trust issued 6,500,000 trust units at $10.00 per unit for gross proceeds of $65 million pursuant to a prospectus.

Trust Units	Number of Units	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	7,135
Unit-based compensation	—	515
Issued for cash, net of expenses	6,500	61,525

Balance December 31, 2003	60,821	$	446,594

Exchangeable Shares

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 cash 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 calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2003 was 1.04530 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Exchangeable Shares	Number of Shares		Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	4,732	$	33,507
Exchanged for trust units	(1,007)		(7,135)
Balance December 31, 2003	3,725	$	26,372

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one exchangeable share and one third of a share of Crew for each common share held.

Common shares of Baytex Energy Ltd.	Number of Shares		Amount
Balance December 31, 2001	52,008	$	394,734
Exercise of stock options	820		3,497
Normal course issuer bid	(9)		(55)
Balance December 31, 2002	52,819		398,176
Flow-through shares issued	103		810
Future tax related to flow-through shares	—		(336)
Exercise of stock options *(note 10)*	5,115		36,239
Transfer of assets under Plan of Arrangement *(note 4)*	—		(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037		410,926
Trust units issued	(53,305)		(377,419)
Exchangeable shares issued	(4,732)		(33,507)
Balance December 31, 2003	—	$	—

Flow-through Shares

In accordance with the terms of flow-through share offerings entered into by the Company and pursuant to certain provisions of the *Income Tax Act* (Canada), the Company fulfilled its commitment to renounce for income tax purposes exploration expenditures of $0.8 million in 2003 to the subscribers of the flow-through shares.

10. TRUST UNIT RIGHTS AND STOCK OPTIONS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. A total of 5,800,000 Trust Unit Rights are reserved for issue under the plan. Trust Unit Rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions provided a certain threshold return on assets is met. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future trust unit prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in income over the vesting period of the plan. The adoption of the amendments related to accounting for unit-based compensation results in compensation expense for the year ended December 31, 2003 of $0.22 million (note 3).

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

	Number of Rights		Weighted Average Exercise Price(1)
Initial grant September 9, 2003	2,593	$	10.23
Granted	380	$	9.60
Cancelled	(118)	$	10.23
Balance December 31, 2003	2,855	$	10.15

(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, 2003:

	Number Outstanding at December 31, 2003	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
Balance December 31, 2003	2,855	4.7	$ 10.15	—	$ —

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised or cancelled as follows:

	Number of Options	Weighted Average Exercise Price
Balance December 31, 2002	5,126	$ 6.98
Granted	121	$ 9.28
Exercised	(5,115)	$ 7.07
Cancelled	(132)	$ 5.44
Balance December 31, 2003	—	$ —

The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as trust units on exercise of the options, with expenses in the first and second quarters increased by $0.32 million and $0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as $32.9 million and $41.8 million would be revised to $32.6 million and $41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter of 2003.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is as follows:

Year Ended December 31	2003	2002
Net income as reported	**38,138**	45,136
Stock-based compensation expense	**(5,522)**	(612)
Pro forma	**32,616**	44,524
Net income per unit		
Basic as reported	**0.69**	0.86
Pro forma	**0.59**	0.85
Diluted as reported	**0.67**	0.85
Pro forma	**0.68**	0.83

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 per option (2002 – $3.65 per option). The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk-free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

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11. 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 exchangeable shares outstanding at year-end, converted at the year-end exchange ratio, have been included in the calculation of the weighted average number of trust units outstanding:

	2003	2002
Weighted average number of units (shares) outstanding	**53,955**	52,298
Trust units issuable on conversion of exchangeable shares	**1,535**	—
Weighted average number of units (shares) outstanding, basic	**55,530**	52,298
Dilutive effect of trust unit incentive rights (stock options)	**990**	939
Weighted average number of units (shares) outstanding, diluted	**56,520**	53,237

The dilutive effect of trust unit incentive rights above did not include 2.7 million trust unit rights (2002 – 2.8 million stock options) because the respective exercise prices exceeded the average market price of the trust units during the year.

12. INCOME TAXES (RECOVERY)

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

	2003	2002
Income before income taxes	**$ 34,170**	$ 92,808
Expected income taxes at the statutory rate of 42.5% (2002 – 44.0%)	**$ 14,526**	$ 40,743
Increase (decrease) in taxes resulting from:		
Crown royalties	**21,451**	21,153
Resource allowance	**(18,334)**	(26,308)
Alberta royalty tax credit	**(213)**	(219)
Net income of the Trust	**(14,191)**	—
Non-taxable portion of foreign exchange gain	**(11,074)**	—

Rate change	**(6,216)**	(138)
Non-cash general and administrative	**314**	—
Other	**106**	2,725
Large corporation tax and provincial capital tax	**9,663**	9,716
Provision for (recovery of) income taxes	**$ (3,968)**	$ 47,672

The components of future income taxes are as follows:

As at December 31	2003	2002
Future income tax liabilities:		
Capital assets	**$ 200,526**	$ 202,429
Other	**2,560**	—
Future income tax assets:		
Provision for future site restoration	**(8,907)**	(9,638)
Reorganization costs	**(19,794)**	(2,833)
Loss carry-forward	**—**	(323)
Other	**—**	(5,233)
Future income taxes	**$ 174,385**	$ 184,402

13. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

	2003	2002
Current assets	**$ (1,840)**	$ 38,528
Current liabilities	**(12,435)**	28,229
	$ (14,275)	$ 66,757

	2003	2002
Changes in non-cash working capital related to:		
Operating activities	**$ (8,060)**	$ 1,272
Investing activities	**(6,215)**	65,485
	$ (14,275)	$ 66,757

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

	2003	2002
Interest	**$ 24,449**	$ 25,482
Current income taxes (refund)	**$ 12,557**	$ (3,298)

14. FINANCIAL INSTRUMENTS

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, 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 long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2003, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2002 – 105 percent).

15. DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. In 2003, petroleum and natural gas sales were reduced by $33.8 million (2002 – $8.3 million) due to derivative contracts.

At December 31, 2003, the Trust had derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2004	5,000 bbls/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbls/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbls/d	US$24.00 – $32.05	WTI

The fair value of the oil derivative contracts at December 31, 2003 is an unrecognized liability of $13.8 million.

Foreign currency	Period	Amount	Exchange Rate	
			Floor	Cap
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3100	CAD/USD $1.3400
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3280	CAD/USD $1.3560
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3160	CAD/USD $1.3365
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3400	CAD/USD $1.3665

The fair value of the foreign currency contracts at December 31, 2003 is an unrecognized asset of $3.7 million.

Interest rate swap	Period	Principal	Rate
	November 2003 to July 2010	US$197,669,000	3-month LIBOR plus 5.2%

The fair value of the interest rate swap at December 31, 2003 is an unrecognized asset of $3.9 million.

16. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

For the period November 2003 to March 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $5.28 and $8.57 per mcf. For the period April 2004 to October 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $4.75 and $6.75 per mcf.

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.

Under the Net Profits Interests Agreement between the Company and the Trust, the Company will establish in 2004 a reclamation fund to fund the payment of environmental and site restoration costs.

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

The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

Consolidated Financial Statements of

BAYTEX ENERGY TRUST

December 31, 2003

Management's Report

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 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 auditors 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.

(signed) "Raymond T. Chan"
Raymond T. Chan, CA
President and Chief Executive Officer
Baytex Energy Ltd.
March 5, 2004

(signed) "Daniel G. Belot"
Daniel G. Belot
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

Auditors' Report
To the Board of Directors of Baytex Energy Ltd.

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated deficit and of cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. 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. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 5, 2004, we reported separately to the Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which excluded Note 17, Differences Between Canadian and United States Generally Accepted Accounting Principles.

(signed) "Deloitte & Touche LLP"
Chartered Accountants

Calgary, Alberta, Canada
March 5, 2004

COMMENT BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING

To the Board of Directors of Baytex Energy Ltd.

In the United States of America, reporting standards for auditors 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 financial statements. As discussed in Note 3 to the consolidated financial statements of Baytex Energy Trust (the "Trust"), in 2003, the Trust adopted recommendations with respect to determining unit-based compensation to conform to new recommendations of Section 3870 of the Canadian Institute of Chartered Accountants and in 2002, the Trust changed its method for accounting for foreign currency translation to conform to new recommendations of Section 1650 of the Canadian Institute of Chartered Accountants. Our report to the board of directors of Baytex Energy Ltd. and the unitholders of the Trust dated March 5, 2004 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.

(signed) "Deloitte & Touche LLP"
Chartered Accountants

Calgary, Alberta, Canada
March 5, 2004

Baytex Energy Trust
Consolidated Balance Sheets
As at December 31, 2003 and 2002
(thousands of Canadian dollars)

	2003	2002
Assets		
Current assets		
Cash and short-term investments	$ 53,731	$ 4,098
Accounts receivable	48,608	52,667
Crude oil inventory	5,900	—
	108,239	56,765
Deferred charges and other assets	7,764	8,679
Petroleum and natural gas properties (note 5)	843,133	932,316
	$ 959,136	$ 997,760
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 80,126	$ 92,563
Distributions payable to unitholders	9,123	—
	89,249	92,563
Long-term debt (note 7)	232,562	326,977
Deferred credits (note 8)	—	12,181
Provision for future site restoration costs	23,483	21,950
Future income taxes (note 12)	174,385	184,402
	519,679	638,073
Commitments and contingencies (note 16)		
Unitholders' Equity		
Unitholders' capital (note 9)	446,594	398,176
Exchangeable shares (note 9)	26,372	—
Contributed surplus (note 10)	224	—
Accumulated distributions	(33,382)	—
Accumulated deficit	(351)	(38,489)
	439,457	359,687
	$ 959,136	$ 997,760

See accompanying notes to the consolidated financial statements.

On behalf of the Board
(signed)"Naveen Dargan"

Naveen Dargan
Director
Baytex Energy Ltd.

(signed) "W.A. Blake Cassidy"

W. A. Blake Cassidy
Director
Baytex Energy Ltd.

Baytex Energy Trust
Consolidated Statements of Operations and Accumulated Deficit
Years Ended December 31, 2003 and 2002
(thousands of Canadian dollars, except per unit data)

	2003	2002

Revenue		
Petroleum and natural gas sales	$ 351,404	$ 365,860
Royalties	(67,175)	(58,922)
	284,229	306,938
Expenses		
Operating	86,034	75,228
General and administrative	8,927	6,743
Unit based compensation (note 10)	739	—
Interest (note 7)	23,548	25,217
Costs on redemption and exchange of notes (note 7)	44,771	—
Foreign exchange gain (note 7)	(52,101)	(2,691)
Depletion and depreciation	116,317	106,834
Site restoration costs	2,973	2,799
Reorganization costs (note 4)	18,851	—
	250,059	214,130
Income before income taxes	34,170	92,808
Income taxes (recovery) (note 12)		
Current	9,663	9,716
Future	(13,631)	37,956
	(3,968)	47,672
Net income	38,138	45,136
Deficit, beginning of year, as previously reported	(38,489)	(75,954)
Accounting policy change for foreign exchange (note 3)	—	(7,671)
Deficit, beginning of year, as restated	(38,489)	(83,625)
Accumulated deficit, end of year	$ (351)	$ (38,489)
Net income per trust unit (note 11)		
Basic	$ 0.69	$ 0.86
Diluted	$ 0.67	$ 0.85

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
Years Ended December 31, 2003 and 2002
(thousands of Canadian dollars)

	2003	2002
Cash provided by (used in):		
Operating activities		
Net income	$ 38,138	$ 45,136
Items not affecting cash:		
Unit based compensation (note 10)	739	—
Amortization of deferred charges	1,027	1,052
Costs on redemption and exchange of notes (note 7)	44,771	—
Foreign exchange gain	(52,101)	(2,691)
Depletion and depreciation	116,317	106,834
Site restoration costs	2,973	2,799
Future income taxes (recovery)	(13,631)	37,956
Cash flow from operations	138,233	191,086
Change in non-cash working capital (note 13)	(8,060)	1,272
(Increase) decrease in deferred charges and other assets	211	(1,057)
Decrease in deferred credits	(2,213)	(18,694)
	128,171	172,607
Financing activities		
Redemption of senior secured notes (note 7)	(89,950)	—
Decrease in bank loan and other debt	—	(76,254)
Increase in deferred charges and other assets	(7,425)	—
Increase in deferred credits	—	12,181
Issue of trust units (note 9)	61,525	—
Payment of distributions	(24,259)	—
Issue of common shares (note 9)	37,049	3,497

Repurchase of common shares	—	(55)
	(23,060)	(60,631)
Investing activities		
Petroleum and natural gas property expenditures	(186,756)	(182,048)
Disposal of petroleum and natural gas properties	137,493	55,580
Properties held for sale	—	(46,895)
Change in non-cash working capital (note 13)	(6,215)	65,485
	(55,478)	(107,878)
Change in cash and short-term investments during the year	49,633	4,098
Cash and short-term investments, beginning of year	4,098	—
Cash and short-term investments, end of year	$ 53,731	$ 4,098

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2003 and 2002
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of the producing and exploratory oil and natural gas assets. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a wholly owned subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. 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 as described in Note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

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 revenues 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 reserve 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.

Cash and Short-term Investments

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

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 in one Canadian cost centre 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 gross proved petroleum and natural gas reserves. 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 (the “ceiling test”). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes, using period end prices and costs. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for Future Site Restoration Costs

Estimates are made of the future site restoration costs relating to the Trust’s petroleum and natural gas properties at the end of their economic life, based on year end values, in accordance with current legislative requirements and industry practice. Annual charges are provided on a unit of production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

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

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.

Deferred Charges and Other Assets

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

Financial Instruments

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 policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use derivative financial instruments for trading or speculative purposes. Gains and losses on derivative contracts are recognized in income based on the underlying financial instrument or the future petroleum and natural gas production in same period that the transactions are settled. The fair values of derivative instruments are not recorded in the consolidated balance sheet.

Gains and losses related to derivative financial instruments that have been closed prior to the end of the term are deferred and recognized in the consolidated statement of operations over the original term of the instrument.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Flow-through Shares

The Company had financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company records

the gross carrying value of the expenditures and records a future tax liability for the tax benefits renounced to subscribers.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 10. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the consolidated financial statements for unexercised rights.

Compensation expense associated with rights granted under the plan is recognized in earnings over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in income in the period of change with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units, including exchangeable shares, outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised. 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 are assumed to be used to purchase trust units at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

Unit-based Compensation Plan

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, “Stock-based Compensation and Other Stock-based Payments” pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as non cash general and administrative expense for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (see Note 10).

Foreign Currency

Effective January 1, 2002, the Company retroactively adopted the CICA amended accounting standard with respect to accounting for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on the year ended December 31, 2002 was to increase net income by $1.8 million. The effect of this change on the December 31, 2001 Consolidated Balance Sheet is an elimination of the unrealized foreign exchange loss of $13.7 million, a decrease in future income taxes of $6.0 million, and an increase in the deficit of $7.7 million.

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4. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement (note 1), the Company transferred to Crew a portion of the Company’s producing and exploratory petroleum and natural gas assets. As this was a related party transaction, assets and liabilities were transferred at carrying value as follows:

Petroleum and natural gas assets and equipment	$ 21,244
Future income tax asset	3,278
Total assets transferred	24,522
Provision for future site restoration	(559)
Net assets transferred and reduction in share capital (note 9)	$ 23,963

Reorganization costs of $18.9 million were expensed in the consolidated statements of operations as a result of the Plan of Arrangement.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31, 2003	As at December 31, 2002
Petroleum and natural gas properties	$ 2,016,382	$ 1,989,246
Accumulated depletion and depreciation	(1,173,249)	(1,056,930)

	$ 843,133	$ 932,316

During 2003, $4.4 million (2002 - $6.7 million) of corporate expenses relating to exploration and development activities were capitalized. No corporate expenses have been capitalized since the inception of operations as a trust effective September 2, 2003. In calculating the depletion and depreciation provision for 2003, $51.1 million (2002 - $80.3 million) of costs relating to undeveloped properties and materials and supplies of $4.0 million (2002- $5.5 million) were excluded from costs subject to depletion and depreciation.

6. BANK CREDIT FACILITIES

On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. 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. The facilities aggregating $165 million are subject to semi-annual review beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

7. LONG-TERM DEBT

	As at December 31,	
	2003	2002
Senior secured notes (2002 US$57,000,000)	$ —	$ 90,037
10.5% senior subordinated notes (2003 - US$247,000; 2002 - US$150,000,000)	319	236,940
9.625% senior subordinated notes (2003 -US$179,699,000)	232,243	—
	$ 232,562	$ 326,977

Senior Secured Notes

On November 13, 1998, the Company issued US$57 million of senior secured notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of $90 million, resulting in a cost of $4.7 million on the redemption. Foreign exchange gains were included in income until the redemption of the notes.

Senior Subordinated Notes

On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

Interest Expense

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

	2003	2002
Bank loan	$ 675	$ 760
Amortization of deferred charges	1,027	1,052
Long-term debt	21,846	23,405
Total interest	$ 23,548	$ 25,217

8. DEFERRED CREDITS

	As at December 31,	
	2003	2002
Deferred interest swap settlement	$ —	$ 12,181

In August 2002, the Company terminated all outstanding interest rate swap agreements for total proceeds of $14.1 million. This amount was deferred and was being amortized as a reduction of interest expense over the original terms of the agreements. The amortization was terminated when the senior secured notes were redeemed and when the exchange offer related to the Old Notes was concluded (note 7). The residual balance was included in the cost on redemption and exchange of notes.

9. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Trust Units

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company.

On December 12, 2003, the Trust issued 6,500,000 trust units at $10.00 per unit for gross proceeds of $65 million pursuant to a prospectus.

Trust Units

	Number of units	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	7,135
Unit-based compensation	—	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003	60,821	$ 446,594

Exchangeable Shares

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 cash 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 calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2003 was 1.04530 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Exchangeable Shares

	Number of shares	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,135)
Balance December 31, 2003	3,725	$ 26,372

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one exchangeable share and one-third of a share of Crew for each common share held.

Common shares of Baytex Energy Ltd.

	Number of shares	Amount
Balance December 31, 2001	52,008	$ 394,734
Exercise of stock options	820	3,497
Normal course issuer bid	(9)	(55)
Balance December 31, 2002	52,819	398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	—	(336)
Exercise of stock options (note 10)	5,115	36,239
Transfer of assets under Plan of Arrangement (note 4)	—	(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued	(53,305)	(377,419)
Exchangeable shares issued	(4,732)	(33,507)
Balance December 31, 2003	—	$ —

Flow-through shares

In accordance with the terms of flow-through share offerings entered into by the Company and pursuant to certain provisions of the Income Tax Act (Canada), the Company fulfilled its commitment to renounce for income tax purposes exploration expenditures of $0.8 million in 2003 to the subscribers of the flow-through shares.

10. TRUST UNIT RIGHTS AND STOCK OPTIONS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. A total of 5,800,000 Trust Unit Rights are reserved for issue under the Plan. Trust Unit Rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions provided a certain threshold return on assets is met. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future trust unit prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in income over the vesting period of the plan. The adoption of the amendments related to accounting for unit-based compensation results in compensation expense for year ended December 31, 2003 was $0.22 million (note 3).

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

	Number of Rights	Weighted average exercise price (1)
Initial grant September 9, 2003	2,593	$ 10.23
Granted	380	$ 9.60
Cancelled	(118)	$ 10.23
Balance December 31, 2003	2,855	$ 10.15

(1) Exercise price reflects grant price less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2003:

	Number Outstanding at December 31, 2003	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
Balance December 31, 2003	2,855	4.7	$ 10.15	—	—

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised or cancelled as follows:

	Number of options	Weighted average exercise price
Balance December 31, 2002	5,126	$ 6.98
Granted	121	$ 9.28
Exercised	(5,115)	$ 7.07
Cancelled	(132)	$ 5.44
Balance December 31, 2003	—	—

The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as trust units on exercise of the options, with expenses in the first and second quarters increased by $0.32 million and $0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as $32.9 million and $41.8 million would be revised to $32.6 million and $41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter of 2003.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is as follows:

	Year Ended December 31	
	2003	2002
Net income as reported	**$ 38,138**	$ 45,136
Stock-based compensation expense	**(5,522)**	(612)
Pro forma	**$ 32,616**	$ 44,524
Net income per unit		
Basic as reported	**$ 0.69**	$ 0.86
Pro forma	**$ 0.59**	$ 0.85
Diluted as reported	**$ 0.67**	$ 0.85
Pro forma	**$ 0.58**	$ 0.83

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 per option (2002 - $3.65 per option). The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

11. 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 exchangeable shares outstanding at year-end, converted at the year-end exchange ratio, have been included in the calculation of the weighted average number of trust units outstanding:

	2003	2002
Weighted average number of units (shares) outstanding	53,995	52,298
Trust units issuable on conversion of exchangeable shares	1,535	—
Weighted average number of units (shares) outstanding, basic	55,530	52,298
Dilutive effect of trust unit incentive rights (stock options)	990	939

Weighted average number of units (shares) outstanding, diluted	56,520	53,237

The dilutive effect of trust unit incentive rights above did not include 2.7 million trust unit rights (2002- 2.8 million stock options) because the respective exercise prices exceeded the average market price of the trust units during the year.

12. INCOME TAXES (RECOVERY)

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

	2003	2002
Income before income taxes	$ 34,170	$ 92,808
Expected income taxes at the statutory rate of 42.5% (2002 - 44.0%)	$ 14,526	$ 40,743
Increase (decrease) in taxes resulting from:		
Crown royalties	21,451	21,153
Resource allowance	(18,334)	(26,308)
Alberta royalty tax credit	(213)	(219)
Net income of the Trust	(14,191)	—
Non-taxable portion of foreign exchange gain	(11,074)	—
Rate change	(6,216)	(138)
Non-cash general and administrative	314	—
Other	106	2,725
Large corporation tax and provincial capital tax	9,663	9,716
Provision for (recovery of) income taxes	$ (3,968)	$ 47,672

The components of future income taxes are as follows:

	As at December 31,	
	2003	2002
Future income tax liabilities:		
Capital assets	$ 200,526	$ 202,429
Other	2,560	—
Future income tax assets:		
Provision for future site restoration	(8,907)	(9,638)
Reorganization costs	(19,794)	(2,833)
Loss carry-forward	—	(323)
Other	—	(5233)
Future income taxes	$ 174,385	$ 184,402

13. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

	2003	2002
Current assets	$ (1,840)	$ 38,528
Current liabilities	(12,435)	28,229
	$ (14,275)	$ 66,757

	2003	2002
Changes in non cash working capital related to:		
Operating activities	$ (8,060)	$ 1,272
Investing activities	(6,215)	65,485
	$ (14,275)	$ 66,757

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

	2003	2002
Interest	$ 24,449	$ 25,482
Current income taxes (refund)	$ 12,557	$ (3,298)

14. FINANCIAL INSTRUMENTS

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, 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 long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2003, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2002- 105 percent).

15. DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. In 2003, petroleum and natural gas sales were reduced by $33.8 million (2002 - $8.3 million) due to derivative contracts.

At December 31, 2003, the Trust had derivative contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2004	5,000 bbls/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbls/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbls/d	US$24.00 – $32.05	WTI

The fair value of the oil derivative contracts at December 31, 2003 is an unrecognized liability of $13.8 million.

	Period	Amount	Exchange Rate	
			Floor	Cap
Foreign currency				
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3100	CAD/USD $1.3400
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3280	CAD/USD $1.3560
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3160	CAD/USD $1.3365
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3400	CAD/USD $1.3665

The fair value of the foreign currency contracts at December 31, 2003 is an unrecognized asset of $3.7 million.

	Period	Principal	Rate
Interest rate swap			
	November 2003 to July 2010	US$179,669,000	3-month LIBOR plus 5.2%

The fair value of the interest rate swap at December 31, 2003 is an unrecognized asset of $3.9 million.

16. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

For the period November 2003 to March 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $5.28 and $8.57 per mcf. For the period April 2004 to October 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $4.75 and $6.75 per mcf.

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.

Under the Net Profits Interests Agreement between the Company and the Trust, the Company will establish in 2004 a reclamation fund to fund the payment of environmental and site restoration costs.

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

Reconciliation of consolidated financial statements to United States Generally Accepted Accounting Principles

The consolidated financial statements included in the Baytex Energy Trust 2003 Annual Report have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), which in most respects, conform to generally accepted accounting principles in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Trust, are as follows:

(a) Under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of 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 or fair value of unproven properties ("ceiling test"). Under Canadian GAAP, this ceiling test is calculated without application of a discount factor, but interest and general and administrative expenses are deducted.

As a result of applying the U.S. GAAP ceiling test in prior years, the Trust recorded additional depletion of $340.7 million before income tax. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, and amortization will differ in subsequent years resulting in U.S. to Canadian GAAP differences.

(b) The Financial Accounting Standards Board ("FASB") has issued Statement of Financial Accounting Standards No. 143, "Accounting for

Asset Retirement Obligations" ("FAS 143"). FAS 143 was adopted prospectively on January 1, 2003 and requires liability recognition for retirement obligations associated with tangible long-lived assets. The initial measurement of the asset retirement obligation is required to be at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. The liability accretes until the expected settlement of the retirement obligation.

This change in accounting policy has been accounted for as a cumulative effect adjustment in the consolidated statement of operations as a loss of $7.1 million, net of income taxes of $5.6 million.

The change in the asset retirement obligation since January 1, 2003 is as follows:

Asset retirement obligation January 1, 2003	$	52,244
Increase in retirement obligations		4,010
Abandonment expenditures		(880)
Property disposition		(3,335)
Accretion		3,957
Asset retirement obligation December 31, 2003	$	55,996

Prior to January 1, 2003, under U.S. GAAP, the provision for future site restoration costs is recorded as a reduction of capital assets. Under Canadian GAAP, effective January 1, 2004, the Trust will adopt new Canadian accounting standards for accounting for asset retirement obligations which are expected to eliminate this difference in future years.

(c) FASB has issued Statement of Financial Accounting Standards No. 123, "Accounting for Stock-based Compensation" ("FAS 123") which establishes financial accounting and reporting standards

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for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by the FAS 123, the Trust elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25"), for all stock options issued by the Company to employees before the effective date of the Plan of Arrangement. Since all stock options were granted with exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by FAS 123, the net income (loss) and net income (loss) per unit for years ended December 31, 2003 and 2002 would have been the pro forma amounts indicated below:

	Year Ended December 31	
	2003	2002
Net income (loss) as reported under U.S. GAAP	$ (9,392)	$ 22,889
Stock based compensation expense	(5,522)	(612)
Pro forma	$ (14,914)	$ 22,277
Net income (loss) per unit:		
Basic as reported	$ (0.17)	$ 0.44
Pro forma	$ (0.27)	$ 0.43
Diluted as reported	$ (0.17)	$ 0.43
Pro forma	$ (0.27)	$ 0.42

The weighted average fair market value of stock options granted by the Company (before the effective date of the Plan of Arrangement) in 2003 was $4.21 per stock option (2002 - $3.65). The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

APB 25 also requires recognition of compensation cost with respect to changes in intrinsic value for variable employee stock compensation plans. As the stock options granted by the Company were modified as part of the Plan of Arrangement, and in prior years certain stock options were repriced, the modified stock options are subject to variable plan accounting, which results in an increase of compensation cost of $12.0 million for the year ended December 31, 2003 (2002 — reduction in compensation cost of $3.7 million) for U.S. GAAP purposes.

After the effective date of the Plan of Arrangement, the Trust established a Trust Unit Incentive Right Plan to replace the stock option plan of the Company. 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. Accordingly, compensation expense is determined as the excess of the market price over the exercise price at the end of each reporting period and is recognized in income over the vesting period of the rights. The accounting for compensation expense for the unit rights plan does not result in a difference between Canadian and U.S. GAAP.

(d) The Company adopted the liability method of accounting for income taxes in 2000 retroactively without restatement. The liability method of accounting for income taxes is similar to Statement of Financial Accounting Standards No. 109, which requires the use of the asset and liability method. The Canadian GAAP liability method requires the measurement of future income tax liabilities and assets using income tax rates that reflect enacted income tax rate reductions provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such reductions only when claimed.

(e) Statement of Financial Accounting Standards No. 133, "Accounting for Derivative instruments and Hedging Activities" (FAS 133), as

modified by Statement No. 138 “Accounting for Certain Derivative Instruments and Certain Hedging Activities”, establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value, and that change in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. This statement requires an entity to establish, at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspects of the hedge. Those methods must be consistent with the entity's approach to managing risk. As hedge accounting was not applied to the financial derivative contracts, at December 31, 2003, the Trust's financial derivative instruments would be recorded as a liability on the consolidated balance sheet at their fair value of $6.2 million (2002 – $14.3 million). FAS 133 also requires that gain and losses on financial derivative instruments be included in the statement of operations when terminated prior to the completion of the contract. As a result, $12.2 million realized on the termination of interest rate swap derivative contracts would be included as an increase of the net income for December 31, 2002. The net loss under U.S. GAAP for the year ended December 31, 2001 was reduced by $18.7 million for the amount realized on renegotiation of financial derivative contracts

(f) The income tax effect of the items noted in (a) through (e) for the year ended December 31, 2003 is a decrease in income taxes of $21.0 million (2002 – decrease of $15.9 million).

(g) Prior to January 1, 2000, the Trust recorded the renouncement of tax deductions resulting from the issuance of flow through shares by reducing petroleum and natural gas properties and unitholders' capital be the estimated cost of the tax deductions renounced. U.S. GAAP requires that flow-though shares be recorded at their fair value without any adjustment for the renouncement of tax deductions and that the estimated costs for the tax deductions be recorded as a future income tax liability rather than a reduction of petroleum and natural gas properties. Subsequent to January 1, 2000, no differences arose in the accounting treatment of flowthrough shares under Canadian GAAP and U.S. GAAP.

(h) 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 believes that it has no other comprehensive income; accordingly comprehensive income is equivalent to net income.

Consolidated Statements of Operations

The application of U.S. GAAP would have the following effect on net income as reported:

	Years Ended December 31	
	2003	2002
Net income (loss) for the year – Canadian GAAP	$ 38,138	$ 45,136
Adjustments:		
Depletion (a)	(41,386)	(2,613)
Accretion (b)	(3,957)	
Compensation expense (c)	(11,972)	(1,873)
Deferred revenue (e)	—	(18,694)
Interest rate swaps (e)	(12,181)	12,181
Financial derivative instruments (e)	8,109	(27,193)
Income taxes (f)	21,006	15,945
Net income (loss) from continuing operations before cumulative effect of change in accounting policy for asset retirement obligations	(2,243)	22,889
Cumulative effect of change in accounting policy for asset retirement obligations (b)	(7,149)	—
Net income (loss) for the year – U.S. GAAP	$ (9,392)	$ 22,889
Net income (loss) from continuing operations before cumulative effect of change in accounting policy for asset retirement obligations per unit		
Basic	$ (0.04)	$ 0.44
Diluted	$ (0.04)	$ 0.43
Net income (loss) per unit – U.S. GAAP		
Basic	$ (0.17)	$ 0.44
Diluted	$ (0.17)	$ 0.43

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported:

		December 31, 2003		
		As Reported	Increase (Decrease)	U.S. GAAP
Assets:				
Capital assets	(a)	$ 843,133	$ (161,477)	$ 697,220
	(b)		15,564	
Liabilities:				
Asset retirement obligations (b)		—	55,996	55,996
Provision for site restoration costs (b)		23,483	(23,483)	—
Financial derivative instruments (e)		—	6,191	6,191
Future income taxes (f)		174,385	(70,961)	103,424
Unitholders' equity:				
Unitholders' capital (g)		446,594	13,942	460,536
Accumulated deficit – see below		(351)	(135,030)	(135,381)

		December 31, 2002		
		As Reported	Increase (Decrease)	U.S. GAAP
Assets:				
Capital assets	(a)	$ 932,316	$ (120,091)	$ 790,275
	(b)		(21,950)	
Liabilities:				
Provision for site restoration costs	(b)	21,950	(21,950)	—
Financial derivative instruments	(e)	—	14,300	14,300
Future income taxes	(f)	184,402	(57,398)	127,004
Deferred credits	(e)	12,181	(12,181)	—
Unitholders' equity:				
Unitholders' capital		398,176	13,942	412,118
Accumulated deficit – see below		(38,489)	(87,500)	(125,989)

	December 31,	
	2003	2002
Accumulated deficit - Canadian GAAP	$ (351)	$ (38,489)
Adjustments to depletion (a)	(169,549)	(128,163)
Flow through share differences (g)	(13,942)	(13,942)
Accretion expense (b)	(3,957)	—
Compensation expense (c)	(13,845)	(1,873)
Financial derivative instruments (e)	(6,191)	(14,300)
Deferred credits (e)	—	12,181
Adjustments to future income taxes (f)	79,603	58,597
Cumulative effect of change in accounting policy for asset retirement obligation (b)	(7,149)	—
Accumulated deficit - U.S. GAAP	$ (135,381)	$ (125,989)

Consolidated Statements of Cash Flow

The application of U.S. GAAP would have the following effect on the operating activities of the consolidated statement of cash flow:

	Years Ended December 31	
	2003	2002
Operating activities		
Cash provided by (used in) operating activities – Canadian GAAP	$ 128,171	$ 172,607
Adjustments:		
Depletion (a)	41,386	2,613
Accretion (b)	3,957	
Compensation expense (c)	11,972	1,873
Deferred revenue (e)	—	18,694
Interest rate swaps (e)	(12,181)	12,181
Financial derivative instruments (e)	(8,109)	27,193
Income taxes (f)	(21,006)	(15,945)
Cash provided by (used in) operating activities – U.S. GAAP	$ 144,190	$ 219,216

Additional U.S. GAAP Disclosure

The Trust presents cash flow before changes in non-cash working capital and other items as a subtotal in the consolidated statement of cash flows. This line item would not be presented in a cash flow statement prepared in accordance with U.S. GAAP. This difference does not result in an adjustment to the financial results as reported under Canadian GAAP.

Recent Developments in U.S. Accounting

In May 2003, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No.150 "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity", which establishes standards for classification and measurement of certain financial instruments. The adoption of this accounting standard did not have a material impact on the Trust.

In January 2003, the FASB issued Interpretation No. 46 "Consolidation of Variable Interest Entities" ("FIN 46"). FIN 46 provides criteria for identifying variable interest entities and for determining what entity, if any, should be included in consolidated financial statements. In December 2003, the FASB issued FIN 46(R) to clarify some of the provisions of FIN 46 and to exempt certain entities from its requirements. The

adoption on January 1, 2004 of this accounting standard is not anticipated to have a material impact on the Trust.

In December 2003, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 104 "Revenue Recognition" ("SAB 104"), which will rescind accounting guidance contained in Staff Accounting Bulletin No. 101 related to multiple element revenue arrangements. The changes noted in SAB 104 are not anticipated to have a material impact on the Trust's financial position, results of operations or cash flows.

The following discussion and analysis, dated March 5, 2004, should be read in conjunction with Baytex Energy Trust's (the "Trust") audited consolidated financial statements for the fiscal years ended December 31, 2003 and 2002. Per 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.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations is not a measure based on generally accepted accounting principles ("GAAP"), but is a financial term commonly used in the oil and gas industry. It represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. 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.

2003 OVERVIEW

The Trust was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of its producing and exploratory petroleum and natural gas assets. As Crew was a related party at the effective date of the Plan of Arrangement, the assets and liabilities were transferred at book value. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. The Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company, its subsidiaries and partnership. After giving effect to the Plan of

Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to Baytex Energy Ltd. 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.

Production

The Trust's average production for fiscal 2003 decreased by six percent to 36,686 boe per day from 39,214 boe per day for fiscal 2002. This decrease was the result of property dispositions that occurred at the end of the first quarter of 2003 and the transfer of the petroleum and natural gas assets to Crew under the Plan of Arrangement effective September 2, 2003.

Light oil production decreased 28 percent to 2,273 barrels per day during 2003 from 3,154 barrels per day in 2002. Heavy oil production during 2003 was 23,911 barrels per day, consistent with production of 23,967 barrels per day during fiscal 2002. Natural gas production for 2003 decreased by 13 percent to 63.0 million cubic feet per day compared to 72.6 million cubic feet per day for the prior year.

Revenue

Petroleum and natural gas sales for 2003 decreased by four percent to $351.4 million from $365.9 million for fiscal 2002. Benchmark WTI crude oil averaged US$31.04 per barrel for 2003, representing a 19 percent increase over the US$26.08 per barrel for 2002. Correspondingly, the Trust's light oil and NGLs price increased to $39.04 per barrel from $33.86 per barrel in 2002. The heavy oil price decreased five percent to $25.12 per barrel in 2003 from $26.39 per barrel in 2002, principally due to the increase in heavy oil differentials. Natural gas prices were 54 percent higher in 2003, averaging $6.07 per thousand cubic feet compared to $3.94 per thousand cubic feet during the previous year. Overall, after accounting for financial derivative contracts, the Trust averaged $26.72 per boe for 2003, a 4 percent increase from $25.56 per boe received in the prior year. For the per-sales-unit calculations, heavy oil sales for 2003 were 650 barrels per day lower than the production for the year due to inventory in transit under the Frontier supply agreement.

Production by Area

	Light Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2003				
Heavy Oil District	**—**	**23,911**	**10.6**	**25,676**
Conventional Oil and Gas District	**2,273**	**—**	**52.4**	**11,010**
Total Production	**2,273**	**23,911**	**63.0**	**36,686**
2002				
Heavy Oil District	—	23,967	10.5	25,710
Conventional Oil and Gas District	3,154	—	62.1	13,504
Total Production	3,154	23,967	72.6	39,214

For 2003, light oil revenue decreased 17 percent over 2002, as the 15 percent increase in wellhead prices was offset by a 28 percent decrease in production. Revenue from heavy oil

decreased eight percent due to a five percent decrease in wellhead prices and a three percent decrease in sales volumes. Natural gas revenue increased 34 percent as the 13 percent production decrease was offset by a 54 percent increase in wellhead prices.

Royalties

For the year ended December 31, 2003, royalties increased 14 percent to $67.2 million from $58.9 million last year and were 17.4 percent of sales compared to 15.7 percent of sales in 2002. Higher realized gas prices resulted in higher royalty rates. Royalties for 2003 were 17.8 percent of sales for light oil, 13.8 percent for heavy oil and 22.9 percent for natural gas. These rates compared to 16.7 percent, 13.9 percent and 19.5 percent, respectively, for 2002.

Operating Expenses

Operating expenses for 2003 increased 14 percent to $86.0 million from $75.2 million for 2002. This increase is attributable to the disposition of properties with lower operating costs and a general increase in field operating costs. Operating expenses were $6.54 per boe for 2003 compared to $5.26 per boe for the prior year. Operating expenses were $8.32 per barrel of light oil, $7.34 per barrel of heavy oil and $0.73 per thousand cubic feet of natural gas for 2003 versus $5.83, $5.99 and $0.61, respectively, for 2002.

Gross Revenue Analysis

	2003		2002	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Light oil	**32,393**	**39.04**	38,985	33.86
Heavy oil	**213,297**	**25.12**	230,874	26.39
Derivative contract loss	**(33,777)**	**(3.62)**	(10,622)	(1.07)
Total oil revenue	**211,913**	**22.74**	259,237	26.19
Natural gas revenue	**139,491**	**6.07**	104,284	3.94
Derivative contract gain	**—**	**—**	2,339	0.09
Total natural gas revenue	**139,491**	**6.07**	106,623	4.03
Total revenue (boe @ 6:1)	**351,404**	**26.72**	365,860	25.56

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/mcf.

Operating Netback

	Light Oil & NGLs ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGLs ($/bbl)		Natural Gas ($/mcf)		BOE ($/boe)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Sales price	**39.04**	33.86	**25.12**	26.39	**26.36**	27.26	**6.07**	3.94	**29.28**	26.14
Royalties	**(6.96)**	(5.67)	**(3.47)**	(3.66)	**(3.78)**	(3.89)	**(1.39)**	(0.77)	**(5.11)**	(4.12)
Operating costs	**(8.32)**	(5.83)	**(7.34)**	(5.99)	**(7.43)**	(5.97)	**(0.73)**	(0.61)	**(6.54)**	(5.26)
Operating netback	**23.76**	22.36	**14.31**	16.74	**15.15**	17.40	**3.95**	2.56	**17.63**	16.76

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

General and administrative expenses for 2003 were $8.9 million, compared to $6.7 million a year ago. On a sales-unit basis, these expenses increased to $0.67 per boe from $0.47 per boe. In accordance with the full-cost accounting policy, $4.4 million of expenses were capitalized in 2003, compared with $6.7 million capitalized in 2002. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation

The Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003.

Compensation expense was also calculated on the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as compensation expense for all stock options granted on or after January 1, 2003. All outstanding stock options were cancelled or exercised effective September 2, 2003.

Interest Expense

For 2003, interest expenses on long-term debt were $23.5 million compared to $25.2 million for 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

Costs on Redemption and Exchange of Notes

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 million of 9.625 percent senior subordinated notes due 2010 in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is $4.7 million of costs on the redemption of the US$57 million senior 7.23 percent secured notes.

Depletion and Depreciation

Depletion and depreciation increased to $116.3 million for 2003 compared to $106.8 million last year. On a sales-unit basis, the provision for 2003 was $8.69 per boe compared to $7.46 per boe for 2002 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument 51-101 ("NI 51-101"), as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

General and Administrative Expenses

($ thousands)	2003	2002
Gross corporate expense	**$ 20,496**	$ 19,328
Operator's recoveries	**(7,166)**	(5,842)
Subtotal	**13,330**	13,486
Full-cost accounting capitalization	**(4,403)**	(6,743)
Net expense	**$ 8,927**	$ 6,743

The ceiling test was calculated at December 31, 2003 using the proved reserves as determined under NI 51-101 and at prices at year-end. No write-down was required at December 31, 2003 under this calculation.

Site Restoration Costs

Site restoration costs for the year ended December 31, 2003 increased to $2.9 million from $2.8 million last year. On a sales-unit basis, the provision for 2003 was $0.22 per boe compared to $0.20 per boe for 2002 due to the changes in the proved reserves used in the calculation.

Foreign Exchange

Foreign exchange gain for 2003 was $52.1 million compared to $2.7 million in 2002. The 2003 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002. The 2002 gain is based on translation at 0.6331 at December 31, 2002 compared to 0.6279 at December 31, 2001.

Income Taxes

Current tax expenses were $9.7 million for 2003 compared to $9.7 million last year. The 2003 current tax expense is comprised of $8.0 million of Saskatchewan Capital Tax and $1.7 million of Large Corporation Tax compared to $8.1 million and $1.6 million, respectively, in 2002.

The fiscal 2003 provision for future income taxes was a recovery of $13.6 million compared to $37.9 million for the prior year. The future income tax recovery for 2003 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income. The federal resource tax changes include a change in the federal income tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. These changes are considered substantially enacted for the purposes of GAAP and the Company's future income tax liability has been reduced accordingly.

Canadian Tax Pools

($ thousands)	December 31, 2003
Cumulative Canadian exploration expense	**9,000**
Cumulative Canadian development expense	**63,000**
Cumulative Canadian oil and gas property expense	**96,000**
Undepreciated capital cost	**148,000**
Other	**48,000**
Total tax pools	**364,000**

Cash Flow from Operations

Cash flow from operations for the year ended December 31, 2003 decreased 28 percent to $138.2 million from $191.1 million for the previous year due to higher costs related to derivative contracts and reorganization under the Plan of Arrangement. On a barrel of oil equivalent basis, cash flow from operations was $10.51 for 2003 compared to $13.35 for 2002.

Capital Expenditures

Exploration and development expenditures increased to $180.1 million for 2003 compared to $136.3 million last year. Total capital expenditures for the last two years are summarized in the table below.

Cash Flow

	2003		2002	
	$/boe	Percent	$/boe	Percent
Production revenue	**29.28**	**100**	26.14	100
Derivative contract loss	**(2.57)**	**(9)**	(0.57)	(2)
Royalties	**(5.11)**	**(17)**	(4.12)	(16)
Operating expenses	**(6.54)**	**(22)**	(5.26)	(20)
Operating netback	**15.06**	52	16.19	62
General and administrative expenses	**(0.68)**	**(2)**	(0.47)	(2)
Reorganization costs	**(1.43)**	**(5)**	—	—
Interest expense	**(1.71)**	**(6)**	(1.69)	(6)
Current income taxes	**(0.73)**	**(3)**	(0.68)	(3)
Cash flow	**10.51**	**36**	13.35	51

Capital Expenditures

($ thousands)	2003	2002
Land	**$ 14,138**	$ 13,834
Seismic	**5,436**	8,183
Drilling and completion	**111,772**	81,862
Equipment	**42,365**	24,507
Other	**6,401**	7,949
Total exploration and development	**180,112**	136,335
Property acquisitions	**6,644**	45,713
Property dispositions	**(137,493)**	(55,580)
Net capital expenditures	**$ 49,263**	$ 126,468

Liquidity and Capital Resources

At December 31, 2003, total net debt (including working capital) was $213.6 million compared to $362.8 million at December 31, 2002. The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from assets sales at the end of March 2003, and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

The Company's debt structure consists of two components. The first component is the senior credit facilities. On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. 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. The facilities aggregating $165 million are subject to semi-annual reviews beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due July 15,2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank credit facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of $65 million.

At December 31, 2003, there were 3.7 million exchangeable shares outstanding. The exchange ratio of these shares was 1.04530 trust units per exchangeable share at year-end. During 2003, a total of 1.0 million exchangeable shares were exchanged for trust units.

Cash Distributions

Total cash distributions of $0.60 per unit were declared from September to December 2003. During the first quarter of 2004, the monthly cash distribution of $0.15 per unit is estimated to be within the Trust's target distribution range of between 60 percent and 70 percent of cash flow.

Off-Balance Sheet Arrangements and Contractual Obligations

The Trust uses various financial derivative instruments, the fair values of which are not reflected on the consolidated balance sheet, to reduce exposure to commodity and currency fluctuations. These risks, and the Trust's risk management policy, are discussed in "Risk and Risk Management." The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

The Trust has ongoing obligations related to abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Contractual Obligations

	Payments Due by Period				
($ thousands)	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Long-term debt(1)	232,562	—	—	—	232,562
Operating leases	1,660	1,328	332	—	—
Transportation agreements	7,295	3,192	3,299	804	—
Total contractual obligations	241,517	4,520	3,631	804	232,562

(1) Total US $179.9 million

Risk 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, revenue and cash flow depends on its success not only in 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 Evaluation Committee, consisting of qualified members of the Company's Board, of the Board of Directors 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 reserve estimates. Any future significant reserve 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 can be managed 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 of Directors. 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 recognizes gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

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 generally 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 denominated long-term debt. 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.

The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

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. These critical estimates are discussed below.

Oil And Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. Unit-of-production calculations are also used in the determination of the site restoration expense. By their inclusion in the unit-of-production calculation, reserve

estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation and site restoration expense.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The ceiling test calculation utilizes and holds constant the prices and costs in effect at the end of the period. An estimate is made of the ultimate recoverable amount from future net revenue using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. The calculation of future net revenue in the ceiling test can be significantly impacted by fluctuations in any of these estimates. An impairment loss is recognized if the amount calculated under the ceiling test is less than the carrying costs of the Trust's petroleum and natural gas assets and can result in a significant accounting loss for a particular period.

New Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective to continue accrual accounting for positions hedged with derivatives. The new guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust is evaluating the impact that the adoption of AcG-13 will have on its results of operations.

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments," pursuant to the transitional provisions contained therein. Under this amended standard, the Trust is required to account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma

earnings impact of related stock-based compensation expense is disclosed in note 10 of the consolidated financial statements.

In March 2003, the CICA issued Section 3110, "Asset Retirement Obligations." This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair 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 new standard is effective for all fiscal years beginning on or after January 1, 2004. The impact of adoption of this standard is estimated to be an increase in asset retirement obligation on the balance sheet of $33 million at December 31, 2003.

In February 2003, the CICA issued Accounting Guideline 14, "Disclosure of Guarantees" ("AcG-14"). AcG-14 establishes the disclosures required for obligations under certain guarantees. The disclosure requirements are effective for interim and annual periods beginning on or after January 1, 2003 and have been made in note 16 of the consolidated financial statements.

In 2003, the CICA issued Accounting Guideline 16, "Oil and Gas Accounting – Full-Cost" ("AcG-16"). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline proposes amendments to the ceiling test calculation applied by the Trust. The ceiling

test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves 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 carrying amount 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. The adoption of this new guideline on January 1, 2004 is not anticipated to have an impact on the financial results of the Trust.

On November 10, 2003, the CICA issued a draft EIC (D37) on “Income Trusts - Exchangeable Units.” The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from unitholder’s equity. This draft EIC is currently under review and was not enacted in final form as of the time of release of the Trust’s 2003 consolidated financial statements.

In June 2003, the CICA issued Accounting Guideline 15, “Consolidation of Variable Interest Entities,” which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the consolidated financial statements of the Trust.

FOURTH QUARTER 2003

The following discussion reviews the Trust’s results of operations for the fourth quarter of 2003.

Total production for the fourth quarter of 2003 decreased nine percent to 36,195 boe per day from 39,890 boe per day for the same period in 2002, due to the sale of properties in March 2003 in the Ferrier area and the transfer of properties

to Crew in September 2003. Petroleum and natural gas sales decreased 23 percent to $77.9 million for the fourth quarter of 2003 from $100.6 million for the fourth quarter of 2002. Total royalties decreased 19 percent to $13.5 million for the fourth quarter of 2003 from $16.7 million for the same period in 2002. Operating expenses for the fourth quarter of 2003 increased 11 percent to $22.1 million from $19.8 million for the corresponding quarter in 2002. Operating expenses were $6.74 per boe for the fourth quarter of 2003 compared to $5.40 per boe for the fourth quarter of 2002.

General and administrative expenses for the fourth quarter of 2003 were $3.6 million compared to $1.6 million in 2002. On a per-sales-unit basis, these expenses were $1.07 per boe compared to $0.44 per boe as no expenses were capitalized in the fourth quarter of 2003 due to lower exploration activity since the effective date of the Plan of Arrangement.

Interest expenses on long-term notes and bank debt were $5.2 million for the fourth quarter of 2003, down from $7.2 million in the same quarter of 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

The foreign exchange gain in the fourth quarter of 2003 was $10.4 million compared to a gain of $1.3 million in the same period in 2002.

The provision for depletion and depreciation increased to $40.4 million for the fourth quarter of 2003 compared to $27.1 million for the same quarter of 2002. On a per-sales-unit basis, the provision for the current quarter was $12.14 per boe compared to $7.39 per boe for the same quarter in 2002, due to the revision in proved reserves under the new standards of disclosure for oil and gas activities, NI 51-101, as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Net income for the fourth quarter of 2003 was $8.9 million compared to $12.8 million for the corresponding quarter of 2002. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

Outstanding Unit Information

At of February 29, 2004, the Trust had 61,027,681 units and 3,530,506 exchangeable shares outstanding. The exchange ratio at February 29, 2004 was 1.07444 trust units per exchangeable share.

Selected Annual Financial Information

($ thousands, except per-unit amounts)	2003	2002	2001
Revenue	**$ 351,404**	$ 365,860	$ 329,700
Net income (loss)	**38,138**	45,136	(137,107)
Per-unit basic	**0.69**	0.86	(2.77)
Per-unit diluted	**0.67**	0.85	(2.77)
Total assets	**959,136**	997,760	967,046
Total long-term financial liabilities	**232,562**	326,977	330,102
Cash distributions declared(1)	**0.60**	—	—

(1) Total unit distributions declared since September 2, 2003.

Overall production for 2003 was 36,686 boe per day which represented a six percent decrease from 39,214 boe per day in 2002. Average

wellhead prices received during 2003 were $29.28 per boe compared to $26.14 during 2002. Production in 2001 was 43,488 boe per day. Average wellhead prices received in 2001 were $21.37 per boe. Total revenue for 2003 was $351.4 million compared to $365.9 million in 2002 and $329.7 million in 2001.

Due to wide heavy oil differentials at year-end 2001, the Trust incurred a $131.3 million ceiling test write-down (net of $103.2 million of future income taxes). This amount was recognized as additional depletion and depreciation for the year ended December 31, 2001.

The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from asset sales at the end of March 2003 and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

Quarterly Financial Information (unaudited)

	2003				2002			
($ thousands, except per-unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	**77,869**	**87,200**	**79,288**	**107,047**	100,590	94,633	91,507	79,130
Cash flow from operations	**30,179**	**19,975**	**33,372**	**54,707**	53,116	48,637	49,208	40,125
Per unit basic	**0.51**	**0.36**	**0.62**	**1.03**	0.69	0.93	0.95	0.77
Per unit diluted	**0.51**	**0.36**	**0.61**	**1.01**	0.67	0.91	0.93	0.76
Net income (loss)	**8,881**	**(45,516)**	**41,830**	**32,943**	12,791	3,687	21,354	7,304
Per unit basic	**0.15**	**(0.83)**	**0.78**	**0.62**	0.24	0.07	0.41	0.14
Per unit diluted	**0.15**	**(0.83)**	**0.76**	**0.61**	0.24	0.07	0.40	0.14
Production								
Light oil and NGLs (bbls/d)	**1,982**	**1,989**	**2,167**	**2,969**	2,909	2,999	2,904	3,818
Heavy oil (bbls/d)	**24,400**	**25,123**	**22,816**	**23,278**	25,009	23,504	24,498	22,838
Total oil and NGLs (bbls/d)	**26,382**	**27,112**	**24,983**	**26,247**	27,918	26,503	27,402	26,656
Natural gas (mmcf/d)	**58.9**	**61.8**	**57.5**	**74.0**	71.8	71.3	73.3	73.7
Barrels of oil equivalent (boe/d @ 6:1)	**36,195**	**37,412**	**34,574**	**38,580**	39,890	38,391	39,625	38,948
Average Prices								
WTI oil (US$/bbl)	**31.18**	**20.20**	**28.91**	**33.86**	28.15	28.27	26.25	21.64
Edmonton par oil ($/bbl)	**39.56**	**40.94**	**41.08**	**50.91**	42.81	44.02	40.40	33.51
BTE light oil ($/bbl)	**36.41**	**34.43**	**37.13**	**45.41**	37.67	37.36	34.53	27.58
BTE heavy oil ($/bbl)	**22.40**	**24.19**	**22.98**	**31.48**	26.09	31.03	26.64	21.58
BTE total oil ($/bbl)	**23.48**	**24.92**	**24.24**	**33.15**	37.30	31.75	27.47	22.44
BTE natural gas ($/mcf)	**5.37**	**5.62**	**6.05**	**7.02**	5.29	3.33	3.94	3.19
BTE oil equivalent ($/boe)	**25.90**	**27.36**	**27.63**	**36.14**	28.64	28.10	26.29	21.39

Exhibit 4

CERTIFICATIONS

I, Raymond T. Chan, President and Chief Executive Officer, certify that:

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

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

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

4. The issuer's other certifying officer(s) 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 we 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 registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

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

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

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

(a) all significant deficiencies and material weakness 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 controls over financial reporting; and

Date: May 19, 2004

By: /s/ Raymond T. Chan
Name: Raymond T. Chan
Title: President and Chief Executive Officer

Exhibit 5

CERTIFICATIONS

I, Daniel G. Belot, Vice-President Finance and Chief Financial Officer, certify that:

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

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

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

4. The issuer's other certifying officer(s) 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 we 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 registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

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

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

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

(a) all significant deficiencies and material weakness 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 controls over financial reporting; and

Date: May 19, 2004

By: /s/ Daniel G. Belot
Name: Daniel G. Belot
Title: Vice President Finance and
Chief Executive Officer

Exhibit 6

Certification

In connection with the annual report of Baytex Energy Trust (the "Trust") on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Raymond T. Chan, President & Chief Executive Officer of Baytex Energy Ltd., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/RAYMOND T. CHAN
Raymond T. Chan
President & Chief Executive Officer
Baytex Energy Ltd.

Dated at Calgary, Alberta, as of May 19, 2004

Exhibit 7

Certification

In connection with the annual report of Baytex Energy Trust (the "Trust") on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Daniel G. Belot, Vice President, Finance and Chief Financial Officer of Baytex Energy Ltd., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/DANIEL G. BELOT
Daniel G. Belot
Vice President, Finance & Chief Financial Officer
Baytex energy Ltd.

Dated at Calgary, Alberta, as of May 19, 2004

Exhibit 8

INDEPENDENT AUDITORS' CONSENT

We consent to the use of our reports dated March 5, 2004, (which auditors' report expresses an unqualified opinion and includes an explanatory paragraph referring to our separate reporting on the consolidated financial statements which excluded Note 17 to the consolidated financial statements) appearing in this Annual Report on Form 40-F of Baytex Energy Trust for the year ended December 31, 2003.

Calgary, Alberta, Canada
May 19, 2004

(signed) "Deloitte & Touche LLP"
Chartered Accountants

Exhibit 9

[SPROULE ASSOCIATES LIMITED LETTERHEAD]

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated March 23, 2004 and effective January 1, 2004, evaluating the oil, natural gas and natural gas liquids reserves attributable to Baytex Energy Trust, entitled “Evaluation of the P&NG Reserves of Baytex Energy Trust (As of January 1, 2004)”, (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, and the Company’s registration statement on Form F-9 (File No. 333-89714).

We also confirm that we have read the Company’s Annual Information Form for the year ended December 31, 2003 dated May 10, 2004 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.

Sincerely,

/s/ Ken H. Crowther

Ken H. Crowther, P.Eng.

President

Calgary, Alberta, Canada

May 19, 2004