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, CA
President and Chief Executive Officer
Baytex Energy Ltd.

[signed]

DANIEL G. BELOT
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

March 7, 2005

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, 2004 and 2003 and the consolidated statements of operations and accumulated income (deficit) and 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, 2004 and 2003 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 7, 2005, 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 20, United States Accounting Principles and Reporting.

[signed]

CALGARY, ALBERTA *CHARTERED ACCOUNTANTS*
March 7, 2005

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31, 2004 AND 2003

(thousands)	**2004**	2003
		(restated – note 3)
ASSETS		
Current assets		
Cash and short-term investments	**$ –**	$ 53,731
Accounts receivable	**41,154**	48,608
Crude oil inventory	**7,299**	5,900
	48,453	108,239
Deferred charges and other assets	**6,491**	7,764
Petroleum and natural gas properties (note 5)	**1,009,933**	866,637
Goodwill (note 4)	**39,259**	–
	$ 1,104,136	$ 982,640
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 72,976**	$ 80,126
Distributions payable to unitholders	**9,981**	9,123
Bank loan (note 6)	**161,444**	–
Financial derivative contracts (note 16)	**9,513**	–
	253,914	89,249
Long-term debt (note 7)	**216,583**	232,562
Asset retirement obligation (note 8)	**73,297**	55,996
Future income taxes (note 13)	**164,909**	170,952
	708,703	548,759
Non-controlling interest (note 10)	**12,962**	25,705
UNITHOLDERS' EQUITY		
Unitholders' capital (note 9)	**515,728**	449,403
Contributed surplus	**7,494**	224
Accumulated distributions	**(146,445)**	(33,382)
Accumulated income (deficit)	**5,694**	(8,069)
	382,471	408,176
	$ 1,104,136	$ 982,640

Commitments and contingencies (note 17)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

[signed]

NAVEEN DARGAN
Director, Baytex Energy Ltd.

[signed]

W. A. BLAKE CASSIDY
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

YEARS ENDED DECEMBER 31, 2004 AND 2003

(thousands, except per unit data)	**2004**	*2003*
		(restated – note 3)
Revenue		
Petroleum and natural gas sales (note 3)	**$ 420,400**	$ 403,022
Royalties	**(65,988)**	(67,175)
Realized loss on financial derivatives	**(78,124)**	(33,777)
Unrealized gain on financial derivatives	**597**	–
	276,885	302,070
Expenses		
Operating	**89,078**	86,034
Transportation (note 3)	**18,714**	17,841
General and administrative	**15,243**	8,927
Unit based compensation (note 11)	**7,736**	739
Interest (note 7)	**19,412**	23,548
Costs on redemption and exchange of notes (note 7)	**–**	44,771
Foreign exchange gain (note 7)	**(15,979)**	(52,101)
Depletion, depreciation and accretion	**160,808**	123,137
Reorganization costs (note 18)	**–**	18,851
	295,012	271,747
Income (loss) before income taxes and non-controlling interest	**(18,127)**	30,323
Income taxes (recovery) (note 13)		
Current	**9,000**	9,663
Future	**(41,237)**	(14,516)
	(32,237)	(4,853)
Income before non-controlling interest	**14,110**	35,176
Non-controlling interest (note 10)	**(347)**	668
Net income	**13,763**	35,844
Accumulated deficit, beginning of year, as previously reported	**(351)**	(38,489)
Accounting policy change for non-controlling interest (note 3)	**529**	–
Accounting policy change for asset retirement obligations (note 3)	**(8,247)**	(5,424)
Accumulated deficit, beginning of year, as restated	**(8,069)**	(43,913)
Accumulated income (deficit), end of year	**$ 5,694**	$ (8,069)
Net income per trust unit (note 12)		
Basic	**$ 0.22**	$ 0.66
Diluted	**$ 0.21**	$ 0.62

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2004 AND 2003

(thousands)	**2004**	2003 *(restated – note 3)*
CASH PROVIDED BY (USED IN):		
OPERATING ACTIVITIES		
Net income	**$ 13,763**	$ 35,844
Items not affecting cash:		
Unit based compensation (note 11)	**7,736**	739
Amortization of deferred charges	**11,171**	1,027
Costs on redemption and exchange of notes (note 7)	**–**	44,771
Unrealized foreign exchange gain	**(15,979)**	(52,101)
Depletion, depreciation and accretion	**160,808**	123,137
Unrealized gain on financial derivatives (note 16)	**(597)**	–
Future income taxes (recovery)	**(41,237)**	(14,516)
Non-controlling interest (note 10)	**347**	(668)
Cash flow from operations	**136,012**	138,233
Change in non-cash working capital (note 14)	**3,589**	(8,060)
Asset retirement expenditures	**(2,739)**	(880)
Decrease in deferred charges and other assets	**212**	211
Decrease in deferred credits	**–**	(2,213)
	137,074	127,291
FINANCING ACTIVITIES		
Redemption of senior secured notes (note 7)	**–**	(89,950)
Increase in bank loan	**161,444**	–
Increase in deferred charges and other assets	**–**	(7,425)
Issue of trust units (note 9)	**44,505**	61,525
Payments of distributions	**(112,074)**	(24,259)
Issue of common shares (note 18)	**–**	37,049
	93,875	(23,060)
INVESTING ACTIVITIES		
Petroleum and natural gas property expenditures	**(184,065)**	(185,876)
Corporate acquisition (note 4)	**(111,042)**	–
Disposal of petroleum and natural gas properties	**14,441**	137,493
Change in non-cash working capital (note 14)	**(4,014)**	(6,215)
	(284,680)	(54,598)
Change in cash and short-term investments during the year	**(53,731)**	49,633
Cash and short-term investments, beginning of year	**53,731**	4,098
Cash and short-term investments, end of year	**$ –**	$ 53,731

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2004 AND 2003

(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"). 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 (note 18).

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.

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

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 than 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 proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

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

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

GOODWILL

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

ASSET RETIREMENT OBLIGATION

The Trust recognizes a liability at discounted fair value for the future abandonment and reclamation costs 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 related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period the actual costs are incurred.

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 DERIVATIVE CONTRACTS

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management 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 financial derivatives for trading or speculative purposes. Financial derivative contracts used as hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with financial derivative contracts. Financial derivative contracts that do not qualify for hedge accounting are recognized in the balance sheet and measured at fair value, with changes in fair value reported separately in the statement of operations as income or expense.

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 book value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company recorded the gross book value of the expenditures and a future tax liability for the tax benefits renounced to subscribers.

UNIT-BASED COMPENSATION

The Trust Unit Rights Incentive Plan is described in note 11. 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 income 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.

NON-CONTROLLING INTEREST

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

PER-UNIT AMOUNTS

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

3. CHANGES IN ACCOUNTING POLICIES

UNIT-BASED COMPENSATION

At December 31, 2003, the Trust elected to 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 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. For the year ended December 31, 2003, compensation expense of $0.22 million was recorded 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. For the year ended December 31, 2003, 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 (note 18).

FULL COST ACCOUNTING

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 modifies 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 recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust (note 17):

	2004	*2005*	*2006*	*2007*	*2008*
WTI ($US/bbl)	29.63	26.80	25.76	26.14	26.53
AECO ($CDN/mcf)	6.03	5.36	4.80	4.91	4.98

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Trust adopted the CICA Section 3110, "Asset Retirement Obligations". This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation costs 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 related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period in which the actual costs were incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by $2.8 million, net of future income tax of $0.8 million. At December 31, 2003 the asset retirement obligations balance increased by $32.5 million to $56.0 million, the petroleum and natural gas assets balance increased by $19.2 million to $862.3 million and the future tax liability decreased by $5.0 million to $169.3 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow as a result of adopting this policy (note 8).

FINANCIAL DERIVATIVE CONTRACTS

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This 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 in order to continue accrual accounting for positions hedged with derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC-128) also became effective. EIC-128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the consolidated balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded a liability of $9.5 million on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $0.6 million in the consolidated statement of operations (note 16).

TRANSPORTATION COSTS

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by $18.7 million (2003 – $17.8 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

NON-CONTROLLING INTEREST

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

As a result of the adoption of EIC 151, net income was reduced in 2004 by $0.35 million for the non-controlling interest's share of income and was increased in 2003 by $0.67 million for the non-controlling interest's share of the loss from the date of the Arrangement. As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a $15.0 million increase in petroleum and natural gas properties (December 2003 – $4.3 million), a $5.7 million increase in future income taxes (December 2003 – $1.6 million) and a $10.9 million increase in unitholders' capital (December 2003 – $2.8 million).

4. CORPORATE ACQUISITION

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. The Company has not yet completed its final valuation of the assets acquired and liabilities assumed and, therefore, the purchase price allocation may be subject to change. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	$ 109,777
Goodwill	39,259
Working capital	1,447
Capital lease obligation	(777)
Asset retirement obligation	(8,435)
Future income taxes	(30,229)
Total net assets acquired	$ 111,042

Financed by:	
Cash	$ 110,822
Costs associated with acquisition	220
Total purchase price	$ 111,042

Goodwill of $39.3 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31,	2004	2003
		(restated – note 3)
Petroleum and natural gas properties	$ 2,342,514	$ 2,042,749
Accumulated depletion and depreciation	(1,332,581)	(1,176,112)
	$ 1,009,933	$ 866,637

In calculating the depletion and depreciation provision for 2004, $61.7 million (2003 – $51.1 million) of costs relating to undeveloped properties and materials and supplies of $3.7 million (2003 – $4.0 million) were excluded from costs subject to depletion and depreciation. During 2003, $4.4 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.

The petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2004 using the following benchmark reference prices for the years 2005 to 2009 adjusted for commodity differentials specific to the Trust (note 17):

	2005	2006	2007	2008	2009
WTI ($US/bbl)	44.29	41.60	37.09	33.46	31.84
AECO ($CDN/mcf)	6.97	6.66	6.21	5.73	5.37

The prices and costs subsequent to 2009 have been adjusted for inflation at an annual rate of 1.5 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with the proved and probable reserves exceeded the book value of the petroleum and natural gas properties.

6. BANK CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit (note 17) 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 $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2004 a total of $161.4 million had been drawn under the credit facilities.

7. LONG-TERM DEBT

As at December 31,	2004	2003
10.5% senior subordinated notes (US$247,000)	$ 297	$ 319
9.625% senior subordinated notes (US$179,699,000)	216,286	232,243
	$ 216,583	$ 232,562

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. In November 2003, the Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

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.

INTEREST EXPENSE

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

	2004	2003
Bank loan	$ 2,256	$ 675
Amortization of deferred charges	1,060	1,027
Long-term debt	16,096	21,846
Total interest	$ 19,412	$ 23,548

8. ASSET RETIREMENT OBLIGATIONS

As at December 31,	2004	2003
		(restated – note 3)
Balance, beginning of the year	$ 55,996	$ 52,244
Liabilities incurred	4,623	4,010
Liabilities settled	(2,739)	(880)
Acquisition of liabilities	12,797	–
Disposition of liabilities	(1,722)	(3,335)
Accretion	4,342	3,957
Balance, end of the year	$ 73,297	$ 55,996

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 55 years with the majority of costs incurred between 2029 and 2060. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2004 is $189 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

9. UNITHOLDERS' CAPITAL

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 (notes 10 and 18).

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus. 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, 3003 pursuant to		
Plan of Arrangement (note 18)	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	9,944
Unit-based compensation	–	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003 (restated – note 3)	60,821	449,403
Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights (1)	113	1,472
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	$ 515,728

(1) Includes compensation expense transferred from contributed surplus.

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a 5 percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. The weighted average closing price is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

10. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either 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 adjusted 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, 2004 was 1.21472 trust units per exchangeable share (2003 – 1.04530 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

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

NON-CONTROLLING INTEREST

	Number of Exchangeable Shares	Amount
Issued September 2, 2003 pursuant to		
Plan of Arrangement (note 18)	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,134)
Non-controlling interest in net income (loss)	–	(668)
Balance December 31, 2003 (restated – note 3)	3,725	25,705
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income (loss)	–	347
Balance December 31, 2004	1,876	$ 12,962

As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a $15.0 million increase in petroleum and natural gas properties (December 2003 – $4.3 million), a $5.7 million increase in future income taxes (December 2003 – $1.6 million) and a $10.9 million increase in unitholders' capital (December 2003 – $2.8 million).

11. TRUST UNIT RIGHTS

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. The accounting for unit-based compensation results in compensation expense for year ended December 31, 2004 of $7.7 million (2003 – $0.22 million).

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
Granted	1,297	$ 11.77
Exercised	(113)	$ 8.87
Cancelled	(502)	$ 9.54
Balance December 31, 2004	3,537	$ 9.60

(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, 2004:

Range of Exercise Prices	*Number Outstanding at December 31, 2004*	*Weighted Average Remaining Term (years)*	*Weighted Average Exercise Price*	*Number Exercisable at December 31, 2004*	*Weighted Average Exercise Price*
$7.21 to $8.49	2,239	3.7	$ 8.34	680	$ 8.34
$8.50 to $9.99	176	4.1	$ 9.12	–	–
$10.00 to $11.49	361	4.6	$11.30	–	–
$11.50 to $13.25	761	4.9	$12.60	–	–
$7.21 to $13.25	3,537	4.0	$ 9.60	680	$ 8.34

12. NET INCOME PER UNIT

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

	2004	*2003*
Weighted average number of units outstanding, basic	**62,574**	53,995
Trust units issuable on conversion of exchangeable shares	**2,635**	1,535
Dilutive effect of trust unit incentive rights	**473**	990
Weighted average number of units outstanding, diluted	**65,682**	56,520

The dilutive effect of trust unit incentive rights above did not include 3.1 million trust unit rights (2003 – 2.7 million) because the respective exercise prices exceeded the average market price of the trust units during the year and the amount of compensation expense attributed to future services and not yet recognized.

13. INCOME TAXES (RECOVERY)

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

	2004	*2003* *(restated – note 3)*
Income (loss) before income taxes and non-controlling interest	**$ (18,127)**	$ 30,323
Expected income taxes (recovery) at the statutory rate of 40.57% (2003 – 42.5%)	**$ (7,354)**	$ 12,887
Increase (decrease) in taxes resulting from:		
Crown royalties	**18,802**	21,451
Resource allowance	**(9,663)**	(18,334)
Alberta royalty tax credit	**(203)**	(213)
Net income of the Trust	**(46,469)**	(14,191)
Non-taxable portion of foreign exchange gain	**(3,241)**	(11,074)
Effect of change in tax rate	**(10,324)**	(5,462)
Effect of change in opening tax pool balances	**8,711**	–
Effect of change in valuation allowance	**5,194**	–
Unit based compensation	**2,949**	314
Other	**361**	106
Large corporation tax and provincial capital tax	**9,000**	9,663
Provision for (recovery of) income taxes	**$ (32,237)**	$ (4,853)

The components of future income taxes are as follows:

As at December 31,		***2004***		*2003*
				(restated – note 3)
Future income tax liabilities:				
Capital assets	$	**193,584**	$	209,425
Other		**12,853**		2,560
Future income tax assets:				
Asset retirement obligation		**(26,072)**		(21,239)
Reorganization costs		**(12,206)**		(19,794)
Loss carry-forward		**(3,250)**		–
Future income taxes	$	**164,909**	$	170,952

14. *CASH FLOW INFORMATION*

INCREASE (DECREASE) IN NON-CASH WORKING CAPITAL ITEMS

		2004		*2003*
Current assets	$	**6,055**	$	(1,840)
Current liabilities		**(5,630)**		(12,435)
	$	**425**	$	(14,275)
Changes in non cash working capital related to:				
Operating activities	$	**3,589**	$	(8,060)
Investing activities		**(4,014)**		(6,215)
	$	**425**	$	(14,275)

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

		2004		*2003*
Interest	$	**21,096**	$	24,449
Current income taxes	$	**17,485**	$	12,557

15. *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 bank debt and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2004, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2003 – 105 percent).

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

16. FINANCIAL 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.

At December 31, 2004, the Trust had derivative contracts for the following:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2005	3,000 bbls/d	US$35.00 – $42.40	WTI
Price collar	Calendar 2005	2,000 bbls/d	US$35.00 – $42.50	WTI
Price collar	Calendar 2005	1,000 bbls/d	US$35.00 – $42.70	WTI
Price collar	Calendar 2005	2,000 bbls/d	US$35.00 – $42.75	WTI

INTEREST RATE SWAP

Period	Principal	Rate
November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

As discussed in note 3, under the new guideline for hedge accounting, the Trust's financial derivative contracts for oil collars do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded a liability of $9.5 million on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $0.6 million in the consolidated statement of operations. The Trust is applying hedge accounting to the interest rate swap and gains and losses are netted against interest expense.

17. 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 percent 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.

At December 31, 2004, there are outstanding letters of credit aggregating $2.2 million issued as security for performance under certain contracts.

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

18. *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 net book 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	$ 23,963

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

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, 2002	52,819	$ 398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	–	(336)
Exercise of stock options	5,115	36,239
Transfer of assets under Plan of Arrangement	–	(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued (note 9)	(53,305)	(377,419)
Exchangeable shares issued (note 10)	(4,732)	(33,507)
Balance December 31, 2003	–	$ –

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 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
Net income as reported (restated – see note 3)	$	35,844
Stock-based compensation expense		(5,522)
Pro forma	$	30,322
Net income per unit		
Basic as reported	$	0.66
Pro forma	$	0.56
Diluted as reported	$	0.62
Pro forma	$	0.52

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 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.

19. SUBSEQUENT EVENT

In January 2005, the Company entered into agreements to collar the exchange rate on US$9 million per month at average $CDN/$US rates between $1.2168 and $1.2500.

20. 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.