MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Trust is responsible for establishing and maintaining adequate internal control over financial reporting over the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2009, our internal control over financial reporting was effective.

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

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 has been audited by Deloitte & Touche LLP, the Trust's Independent Registered Chartered Accountants, who also audited the Trust's Consolidated Financial Statements for the year ended December 31, 2009.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

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

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

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

March 15, 2010

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

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

We have audited the consolidated balance sheets of Baytex Energy Trust and subsidiaries (the "Trust") as at December 31, 2009 and 2008, and the consolidated statements of income and comprehensive income, deficit, and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2010 expressed an unqualified opinion on the Trust's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

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

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Trust's financial statements, such as the changes described in Notes 3 and 21 to the consolidated financial statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Unitholders of Baytex Energy Trust, dated March 15, 2010, 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.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

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

We have audited the internal control over financial reporting of Baytex Energy Trust and subsidiaries (the "Trust") as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of the Trust and our report dated March 15, 2010 expressed an unqualified opinion on those financial statements and included a separate report titled Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Difference referring to changes in accounting principles.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
March 15, 2010

CONSOLIDATED BALANCE SHEETS

As at December 31	2009	2008
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Cash	$ 10,177	$ –
Accounts receivable	137,154	87,551
Crude oil inventory	1,384	332
Future income tax asset (note 15)	1,371	–
Financial derivative contracts (note 18)	29,453	85,678
	179,539	173,561
Future income tax asset (note 15)	418	–
Financial derivative contracts (note 18)	2,541	–
Petroleum and natural gas properties (note 5)	1,663,752	1,601,017
Goodwill	37,755	37,755
	$ 1,884,005	$ 1,812,333
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities (note 18)	$ 180,493	$ 164,353
Distributions payable to unitholders (note 18)	19,674	17,583
Bank loan (note 18)	265,088	208,482
Convertible debentures (note 8)	7,736	–
Future income tax liability (note 15)	8,683	25,358
Financial derivative contracts (note 18)	4,650	–
	486,324	415,776
Long-term debt (note 7)	150,000	217,273
Convertible debentures (note 8)	–	10,195
Asset retirement obligations (note 9)	54,593	49,351
Future income tax liability (note 15)	179,673	192,411
Financial derivative contracts (note 18)	1,418	–
	872,008	885,006
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	1,295,931	1,129,909
Conversion feature of convertible debentures (note 8)	374	498
Contributed surplus (note 13)	20,371	21,234
Accumulated other comprehensive loss (note 11)	(3,899)	–
Deficit	(300,780)	(224,314)
	1,011,997	927,327
	$ 1,884,005	$ 1,812,333

Commitments and contingencies (note 19)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Gregory K. Melchin
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Years Ended December 31	2009	2008
(thousands of Canadian dollars, except per unit amounts)		
Revenue		
Petroleum and natural gas	$ 789,820	$ 1,159,718
Royalties	(130,715)	(207,522)
Gain on financial derivative contracts (note 18)	26,008	59,816
	685,113	1,012,012
Expenses		
Operating	163,250	172,471
Transportation and blending	159,354	218,706
General and administrative	35,006	29,603
Unit-based compensation (note 13)	6,443	7,812
Interest (note 16)	32,685	32,512
Financing charges (note 16)	5,496	450
Foreign exchange (gain) loss (note 17)	(22,824)	37,746
Depletion, depreciation and accretion	237,216	223,900
	616,626	723,200
Income before income taxes and non-controlling interest	68,487	288,812
Income tax expense (recovery) (note 15)		
Current	11,370	10,177
Future	(30,457)	15,383
	(19,087)	25,560
Income before non-controlling interest	87,574	263,252
Non-controlling interest (note 12)	–	(3,358)
Net income	$ 87,574	$ 259,894
Other comprehensive loss		
Foreign currency translation adjustment (note 11)	(3,899)	–
Comprehensive income	$ 83,675	$ 259,894
Net income per trust unit (note 14)		
Basic	$ 0.83	$ 2.83
Diluted	$ 0.82	$ 2.74
Weighted average trust units (note 14)		
Basic	104,894	91,683
Diluted	107,246	96,391

CONSOLIDATED STATEMENTS OF DEFICIT

Years Ended December 31	2009	2008
(thousands of Canadian dollars)		
Deficit, beginning of year	$ (224,314)	$ (239,727)
Net income	87,574	259,894
Distributions to unitholders	(164,040)	(244,481)
Deficit, end of year	$ (300,780)	$ (224,314)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(thousands of Canadian dollars)*	2009	2008
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 87,574	$ 259,894
Items not affecting cash:		
Unit-based compensation (note 13)	6,443	7,812
Unrealized foreign exchange (gain) loss	(2,623)	41,712
Depletion, depreciation and accretion	237,216	223,900
Accretion on debentures and notes (notes 7 & 8)	2,908	1,681
Unrealized loss (gain) on financial derivative contracts (note 18)	54,810	(119,917)
Future income tax expense (recovery) (note 15)	(30,457)	15,383
Non-controlling interest (note 12)	–	3,358
Realized foreign exchange gain on redemption of long-term debt (notes 7 & 17)	(23,685)	–
	332,186	433,823
Change in non-cash working capital (note 17)	(27,878)	38,857
Asset retirement expenditures (note 9)	(1,146)	(1,443)
	303,162	471,237
Financing activities		
Payments of distributions	(136,409)	(194,728)
Increase (decrease) in bank loan	64,181	(33,236)
Redemption of long-term debt (note 7)	(196,411)	–
Issuance of long-term debt (note 7)	150,000	–
Issuance of trust units (note 10)	135,581	10,502
Issuance costs (note 10)	(6,101)	–
	10,841	(217,462)
Investing activities		
Petroleum and natural gas property expenditures	(164,094)	(185,083)
Acquisition of petroleum and natural gas properties, net	(133,077)	(88,566)
Change in non-cash working capital (note 17)	(6,587)	19,874
	(303,758)	(253,775)
Impact of foreign exchange on cash balances	(68)	–
Change in cash	10,177	–
Cash, beginning of year	–	–
Cash, end of year	$ 10,177	$ –

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2009 AND 2008

(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 and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Pursuant to the Plan of Arrangement, the Company became a subsidiary of the Trust.

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

The significant differences between Canadian and United States GAAP ("U.S. GAAP"), as applicable to these consolidated financial statements and notes, are described in note 21.

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. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

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

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

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

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

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

Cash and Cash Equivalents

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

Crude Oil Inventory

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

Petroleum and Natural Gas Operations

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

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

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test ("ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the estimated 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 estimated 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 estimated future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

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

Convertible Debentures

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

Asset Retirement Obligations

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

Joint Interests

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

Foreign Currency Translation

Transactions completed in foreign currencies are reflected in Canadian dollars at the foreign currency exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in foreign currencies are reflected in the financial statements at the Canadian equivalent at the rate of exchange prevailing at the balance sheet date. Gains and losses are included in earnings.

The foreign operations are considered to be "self-sustaining operations". As a result, the revenues and expenses are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in unitholders' equity.

Revenue Recognition

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

Financial Instruments

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

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

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

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

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

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are expensed immediately.

Financial Derivative Contracts

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

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

Future Income Taxes

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

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 13. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

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

Non-controlling Interest

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

Per-unit Amounts

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

3. CHANGES IN ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 20, 2009, the Trust adopted the following new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA") during 2009: Section 3064 "Goodwill and Intangible Assets" and EIC-173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". EIC-173 was adopted retrospectively without restatement of prior periods.

Goodwill and Intangible Assets

Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to their initial recognition. The adoption of this new standard did not have a material impact on the consolidated financial statements of the Trust.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

EIC-173 provides guidance on how to take into account the credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of EIC-173 did not have a material impact on the consolidated financial statements of the Trust.

Financial Instruments – Disclosures

In June 2009, the CICA amended Section 3862 "Financial Instruments – Disclosures" to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Refer to note 18 "Financial Instruments and Risk Management" for the enhanced disclosures and liquidity risk disclosures.

Financial Instruments – Recognition and Measurement

In July 2009, the CICA amended Section 3855, "Financial Instruments – Recognition and Measurement", in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and provided that certain conditions have been met, permit reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The adoption of this amended standard on December 31, 2009 did not have a material impact on the consolidated financial statements of the Trust.

Change in Foreign Currency Translation

The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date (0.9555 USD/CAD), while revenues and expenses are translated using the average exchange rate for the period (0.8760 USD/CAD). Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity and are recognized in net income when there has been a reduction in net investment.

Previously, foreign operations were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate while other assets and liabilities were translated at the historical rate. Revenues and expenses were translated at the average monthly rate except for depletion, depreciation and accretion, which were translated on the same basis as the assets to which they relate. Translation gains and losses were included in the determination of net income for the period.

This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties.

Future Accounting Changes

Business Combinations

In January 2009, the CICA issued Section 1582 "Business Combinations" which establishes principles and requirements of the acquisition method for business combinations and related disclosures. The purchase price is to be based on trading data at the closing date of the acquisition, not the announcement date of the acquisition, and most acquisition costs are to be expensed as incurred. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2011. The adoption of this standard may have an impact on the Trust's accounting for future business combinations.

Consolidated Financial Statements

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" which establishes standards for the preparation of consolidated financial statements and Section 1602 "Non-controlling Interests" which provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The Trust plans to adopt these standards prospectively effective January 1, 2011. The adoption of these standards may have an impact on the Trust's accounting for future business combinations.

4. CORPORATE ACQUISITIONS

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

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

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	3,934
Total purchase price	$ 180,467
Allocation of purchase price:	
Property, plant and equipment	$ 219,913
Future income taxes	(37,910)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 180,467

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

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31	
	2009	2008
Petroleum and natural gas properties	**$ 3,943,850**	$ 3,648,431
Accumulated depletion and depreciation	**(2,280,098)**	(2,047,414)
	$ 1,663,752	$ 1,601,017

In calculating the Canadian cost centre depletion and depreciation provision for 2009, $47.7 million (2008 – $63.6 million) of costs relating to undeveloped properties were excluded, while $538.3 million (2008 – $385.0 million) of future development costs were included for the calculation. In calculating the U.S. cost centre depletion and depreciation provision for 2009, $77.0 million (2008 – $57.6 million) of costs relating to undeveloped properties were excluded, while $77.3 million (2008 – $56.3 million) of future development costs were included for the calculation. No general and administrative expenses have been capitalized since the inception of operations as a trust.

Depletion and depreciation expense related to the Canadian and U.S. cost centres in 2009 were $228.8 million and $4.2 million respectively (2008 – $218.4 million and $1.7 million).

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2009 using the following benchmark reference prices for the years 2010 to 2014 adjusted for commodity differentials specific to the Trust:

	2010	2011	2012	2013	2014
WTI crude oil (US$/bbl)	79.17	84.46	86.89	90.20	92.01
AECO natural gas ($/MMBtu)	5.36	6.21	6.44	7.23	7.98
Exchange rate (USD/CAD)	0.92	0.92	0.92	0.92	0.92

The prices and costs subsequent to 2014 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculations, the Trust's estimated undiscounted future net cash flows associated with proved reserves plus the cost less impairment of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. In June 2009, total credit facilities were increased to $515 million from $485 million. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. The credit facilities mature on June 30, 2010 and are eligible for extension. At December 31, 2009 a total of $265.1 million was drawn under the credit facilities (December 31, 2008 – $208.5 million).

7. LONG-TERM DEBT

	December 31, 2009	December 31, 2008
9.15% senior unsecured debentures	$ 150,000	$ –
10.5% senior subordinated notes (US$247)	–	303
9.625% senior subordinated notes (US$179,699)	–	220,059
	150,000	220,362
Discontinued fair value hedge	–	(3,089)
	$ 150,000	$ 217,273

On August 26, 2009, the Trust issued $150.0 million Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. These debentures are unsecured and are subordinate to the Company's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Trust's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525%, and 2015 at 100%.

On September 25, 2009, the Company redeemed all of the 9.625% senior subordinated notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% senior subordinated notes due February 15, 2011 (principal amount US$0.2 million) for an aggregate redemption price of $196.4 million. These notes were unsecured and were subordinate to the Company's bank credit facilities. These notes were carried at amortized cost, net of a discontinued fair value hedge. The notes accrete up to the principal balance at maturity using the effective interest method.

The Company recorded accretion expense of $2.8 million for the year ended December 31, 2009 (2008 – $1.6 million). The effective interest rate applied was 10.6%. The discontinued fair value hedge has been recognized in accretion expense upon redemption of the senior subordinated notes.

8. CONVERTIBLE DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	–	97	–
Balance, December 31, 2008	10,398	$ 10,195	$ 498
Conversion	(2,583)	(2,544)	(124)
Accretion	–	85	–
Balance, December 31, 2009	**7,815**	**$ 7,736**	**$ 374**

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully-paid trust units at a conversion price of $14.75 per trust unit. At December 31, 2009, the debentures are classified as a current liability as they mature and are due and payable on December 31, 2010.

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

9. ASSET RETIREMENT OBLIGATIONS

	December 31, 2009	December 31, 2008
Balance, beginning of year	$ 49,351	$ 45,113
Liabilities incurred	1,320	871
Liabilities settled	(1,146)	(1,443)
Acquisition of liabilities	3,268	1,536
Disposition of liabilities	(146)	(904)
Accretion	4,184	3,802
Change in estimate[(1)]	(2,212)	376
Foreign exchange	(26)	–
Balance, end of year	$ 54,593	$ 49,351

(1) Changes in the status of wells and changes in the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on its 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 52 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2009 is $279.3 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 2.0%.

10. UNITHOLDERS' CAPITAL

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

	Number of units	Amount
Balance, December 31, 2007	84,540	$ 821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of unit rights	1,386	10,653
Transfer from contributed surplus on exercise of unit rights	–	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	97,685	$ 1,129,909
Issued for cash	7,935	115,058
Issuance costs, net of income tax	–	(5,072)
Issued on conversion of debentures	175	2,667
Issued on exercise of unit rights	2,059	20,523
Transfer from contributed surplus on exercise of unit rights	–	7,306
Issued pursuant to distribution reinvestment plan	1,445	25,540
Balance, December 31, 2009	**109,299**	**$ 1,295,931**

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

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

11. ACCUMULATED OTHER COMPREHENSIVE LOSS

	December 31, 2009	December 31, 2008
Balance, beginning of year	**$ –**	$ –
Foreign currency translation adjustment	**(3,899)**	–
Balance, end of year	**$ (3,899)**	$ –

Accumulated other comprehensive loss is composed entirely of currency translation adjustments on the foreign operations. The Trust's foreign operations are considered to be "self-sustaining operations", financially and operationally independent, as of January 1, 2009. This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties.

12. NON-CONTROLLING INTEREST

On May 30, 2008, the Trust announced that the Company had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for trust units in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2009, and December 31, 2008, there were no exchangeable shares outstanding.

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

	Number of Exchangeable Shares	Amount
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	–	3,358
Balance, December 31, 2008 and 2009	–	$ –

13. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of unit rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Plan. Under the Plan, unit rights have a maximum term of five years and vest and become exercisable as to one-third on each of the first, second and third anniversaries of the grant date. The Plan provides that the exercise price of the unit rights may be reduced to account for future distributions, subject to certain performance criteria. Effective November 16, 2009, the Plan was amended to (i) base the exercise price of unit rights on the closing price of the trust units on the trading day prior to the date of grant (previously based on a five-day volume weighted average trading price) and (ii) permit the granting of unit rights with a fixed exercise price.

The Trust recorded compensation expense of $6.4 million for the year ended December 31, 2009 (year ended December 31, 2008 – $7.8 million) related to the unit rights granted under the Plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $6.38 per unit for unit rights issued during the year ended December 31, 2009 ($2.42 per unit for the year ended December 31, 2008). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2009	2008
Expected annual exercise price reduction (on rights with declining exercise price)	**$1.44 – $2.16**	$2.16 – $3.00
Expected volatility	**39% – 43%**	28% – 39%
Risk-free interest rate	**1.78% – 2.72%**	2.98% – 4.17%
Expected life of unit rights (years)[1]	**Various**	Various

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

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

	Number of unit rights	Weighted average exercise price(1)
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	8,449	$ 14.58
Granted	1,844	$ 24.87
Exercised	(2,059)	$ 9.97
Cancelled	(114)	$ 16.43
Balance, December 31, 2009	8,120	$ 16.68

(1) Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.

The following table summarizes information about the unit rights outstanding at December 31, 2009:

Range of Exercise Prices	Number Outstanding at December 31, 2009	Weighted Average Remaining Term *(years)*	Weighted Average Exercise Price	Number Exercisable at December 31, 2009	Weighted Average Exercise Price
$ 2.93 to $ 8.00	814	0.8	$ 6.15	814	$ 6.15
$ 8.01 to $13.00	201	1.3	$ 9.34	180	$ 9.06
$13.01 to $18.00	5,371	3.0	$ 15.53	2,944	$ 15.39
$18.01 to $23.00	372	3.8	$ 21.04	–	$ 18.15
$23.01 to $27.72	1,362	4.9	$ 27.42	10	$ 24.89
$ 2.93 to $27.72	8,120	3.1	$ 16.68	3,948	$ 13.22

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2007	$ 18,527
Compensation expense	7,812
Transfer from contributed surplus on exercise of unit rights(1)	(5,105)
Balance, December 31, 2008	$ 21,234
Compensation expense	6,443
Transfer from contributed surplus on exercise of unit rights(1)	(7,306)
Balance, December 31, 2009	$ 20,371

(1) Upon exercise of unit rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

14. NET INCOME PER UNIT

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

	December 31, 2009			December 31, 2008		
	Net income	Trust units	Net income per unit	Net income	Trust units	Net income per unit
Net income per basic unit	$ 87,574	104,894	$ 0.83	$ 259,894	91,683	$ 2.83
Dilutive effect of unit rights	–	1,697		–	2,955	
Conversion of convertible debentures	502	655		654	882	
Exchange of exchangeable shares	–	–		3,358	871	
Net income per diluted unit	$ 88,076	107,246	$ 0.82	$ 263,906	96,391	$ 2.74

For the year ended December 31, 2009, 1.6 million unit rights (year ended December 31, 2008 – 45,000) were excluded in calculating the weighted average number of diluted trust units outstanding as they were anti-dilutive.

15. INCOME TAXES

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

	Years Ended December 31	
	2009	2008
Income before income taxes and non-controlling interest	$ 68,487	$ 288,812
Expected income taxes at the statutory rate of 29.48% (2008 – 30.22%)	20,190	87,279
Increase (decrease) in income taxes resulting from:		
Net income of the Trust	(50,474)	(79,930)
Non-taxable portion of foreign exchange (gain) loss	(2,994)	6,204
Effect of change in income tax rate	601	(1,402)
Effect of change in opening tax pool balances	5,501	878
Effect of change in valuation allowance	(5,374)	–
Unit-based compensation	1,899	2,361
Other	194	(7)
Future income tax (recovery) expense	(30,457)	15,383
Current income tax expense	11,370	10,177
Income tax (recovery) expense	$ (19,087)	$ 25,560

The components of the net future income tax liability are as follows:

	As at December 31	
	2009	2008
Future income tax liabilities:		
Petroleum and natural gas properties	$ 200,820	$ 197,694
Financial derivative contracts	9,432	25,358
Other	5,438	14,215
Future income tax assets:		
Asset retirement obligations	(13,929)	(12,652)
Non-capital loss carry-forward	(13,185)	(11,813)
Valuation allowance on non-capital losses	–	4,967
Financial derivative contracts	(1,789)	–
Other	(220)	–
Net future income tax liability(1)	186,567	217,769
Current portion of net future income tax liability	7,312	25,358
Long-term portion of net future income tax liability	$ 179,255	$ 192,411

(1) Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken totaled $48.4 million ($42.9 million in 2008) and expire from 2014 to 2028.

16. INTEREST EXPENSE AND FINANCING CHARGES

The Trust incurred interest expense and financing charges on its outstanding debts as follows:

	Years Ended December 31	
	2009	2008
Bank loan and other	$ 9,394	$ 12,235
Long-term debt	22,578	19,332
Convertible debentures	713	945
Financing charges	5,496	450
Interest expense and financing charges	$ 38,181	$ 32,962

17. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	2009	2008
Current assets	$ (50,655)	$ 35,460
Current liabilities	16,140	23,271
Foreign exchange	50	–
	$ (34,465)	$ 58,731
Changes in non-cash working capital related to:		
Operating activities	$ (27,878)	$ 38,857
Investing activities	(6,587)	19,874
	$ (34,465)	$ 58,731

Supplemental Cash Flow Information

During the year the Trust made the following cash outlays in respect of interest, financing charges and current income taxes paid:

	Years Ended December 31	
	2009	2008
Interest paid	$ 33,002	$ 30,205
Financing charges paid	$ 5,278	$ 450
Current income taxes paid	$ 10,534	$ 9,972

Foreign Exchange (Gain) Loss

	Years Ended December 31	
	2009	2008
Unrealized foreign exchange (gain) loss	$ (2,623)	$ 41,712
Realized foreign exchange (gain)[1]	(20,201)	(3,966)
Foreign exchange (gain) loss	$ (22,824)	$ 37,746

(1) *The retirement of the US$ senior subordinated notes on September 25, 2009 resulted in a realized gain of $51.0 million. Only $23.7 million of this gain is recognized in the twelve months ended December 31, 2009 as $27.3 million was reported in prior periods as an unrealized foreign exchange gain through the translation process at each period end.*

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Categories of Financial Instruments

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

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Held for trading				
Cash	$ 10,177	$ 10,177	$ –	$ –
Derivatives designated as held for trading	31,994	31,994	85,678	85,678
Total held for trading	$ 42,171	$ 42,171	$ 85,678	$ 85,678
Loans and receivables				
Accounts receivable	$ 137,154	$ 137,154	$ 87,551	$ 87,551
Total loans and receivables	$ 137,154	$ 137,154	$ 87,551	$ 87,551
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	$ (6,068)	$ (6,068)	$ –	$ –
Total held for trading	$ (6,068)	$ (6,068)	$ –	$ –
Other financial liabilities				
Accounts payable and accrued liabilities	$ (180,493)	$ (180,493)	$ (164,353)	$ (164,353)
Distributions payable to unitholders	(19,674)	(19,674)	(17,583)	(17,583)
Bank loan	(265,088)	(265,088)	(208,482)	(208,482)
Long-term debt	(150,000)	(162,750)	(217,273)	(200,557)
Convertible debentures	(7,736)	(15,474)	(10,195)	(9,837)
Total other financial liabilities	$ (622,991)	$ (643,479)	$ (617,886)	$ (600,812)

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

Fair Value of Derivatives

The Trust classifies the fair value of derivatives according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The following table presents the Trust's fair value hierarchy for those assets and liabilities measured at fair value on a recurring basis as of December 31, 2009. The fair value measurement of financial derivative contracts related to the Trust's foreign currency swaps, interest rate swaps and commodity price collars are considered Level 2.

As at December 31, 2009	Level 1	Level 2	Level 3	Total
Derivatives designated as held for trading	–	$ 25,926	–	$ 25,926

Financial Risk

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

Market Risk

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

Foreign currency risk

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

To manage the impact of currency exchange rate fluctuations, the Trust may enter into agreements to fix the Canada – U.S. exchange rate.

At December 31, 2009, the Trust had in place the following currency contracts:

Type	Period	Amount per month	Sales Price[1]
Forward sales	October 1, 2009 to December 31, 2010	US$ 1.0 million	1.0870
Forward sales	January 1, 2010 to December 31, 2010	US$10.0 million	1.1889
Forward sales	January 1, 2010 to March 31, 2011	US$ 5.0 million	1.1500
Forward sales	January 1, 2010 to December 31, 2011	US$ 5.0 million	1.0711

(1) Based on the weighted average exchange rate (CAD/USD).

The following table demonstrates the effect of movements in the Canada-United States exchange rate on net income before income taxes due to changes in the fair value of the currency swaps as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2009.

	$0.01 Increase (Decrease) in CAD/USD Exchange Rate
Loss (gain) on currency forward sales agreements	$ 3,060
Loss (gain) on other monetary assets/liabilities	1,565
Impact on income before income taxes and other comprehensive income	$ 4,625

The carrying amounts of the Trust's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2009	December 31, 2008	**December 31, 2009**	December 31, 2008
U.S. dollar denominated	**US$ 67,389**	US$ 84,070	**US$ 198,690**	US$ 191,571

Subsequent to December 31, 2009, the Trust added the following currency contract:

Type	Period	Amount per month	Sales Price[1]
Forward sales	January 1, 2011 to December 31, 2011	US$ 3.0 million	1.0647

(1) Based on the weighted average exchange rate (CAD/USD).

Interest rate risk

The Trust's interest rate risk arises from its floating rate bank credit facilities. As at December 31, 2009, $265.1 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 100 basis points in interest rates would impact net income before taxes for the year ended December 31, 2009 by approximately $2.0 million. The Trust uses a combination of short-term and long-term debt to finance operations. Short-term debt is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

At December 31, 2009, the Trust had the following interest swap financial derivative contracts:

Type	Period	Amount per month	Fixed interest rate	Floating rate index
Swap – pay floating, receive fixed	September 23, 2009 to August 26, 2011	Cdn$150.0 million	9.15%	3 month BA plus 7.875%
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3 month LIBOR
Swap – pay fixed, receive floating	September 25, 2012 to September 25, 2014	US$90.0 million	4.39%	3 month LIBOR

When assessing the potential impact of forward interest rate changes, an increase or decrease of 100 basis points would result in an increase or decrease, respectively, to the unrealized gain of $2.0 million relating to financial derivative instruments outstanding as at December 31, 2009.

Commodity Price Risk

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

When assessing the potential impact of oil price changes on the financial derivative instruments outstanding as at December 31, 2009, a 10% increase would result in a reduction to the unrealized gain as at December 31, 2009 of $16.5 million, while a 10% decrease would result in an increase to the unrealized gain as at December 31, 2009 of $18.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative instruments outstanding as at December 31, 2009, a 10% increase would result in a reduction to the unrealized gain as at December 31, 2009 of $2.9 million, while a 10% decrease would result in an increase to the unrealized gain as at December 31, 2009 of $3.9 million.

Financial Derivative Agreements

At December 31, 2009, the Trust had the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Buy	Calendar 2010	575 bbl/d	US$64.00	WTI
Fixed – Sell	Calendar 2010	1,200 bbl/d	US$77.78	WTI
Collar – Sell	Calendar 2010	2,000 bbl/d	US$70.00 – 95.65	WTI
Collar – Sell	Calendar 2010	1,000 bbl/d	US$75.00 – 87.60	WTI
Fixed – Sell	Calendar 2010	1,000 bbl/d	US$83.10	WTI
Fixed – Sell	Calendar 2010	770 bbl/d	US$82.30	WTI
Fixed – Sell	Calendar 2010	1,000 bbl/d	US$80.08	WTI

Natural Gas	Period	Volume	Price/Unit	Index
Fixed – Sell	January to February 2010	10,000 MMBtu/d	US$5.63 – 5.66	NYMEX
Fixed – Sell	January to April 2010	3,000 GJ/d	Cdn$4.54	AECO
Fixed – Sell	March 2010	2,500 MMBtu/d	US$4.78	NYMEX
Fixed – Buy	March 2010	2,500 MMBtu/d	US$5.83	NYMEX
Collar – Sell	April 2009 to December 2010	5,000 GJ/d	Cdn$5.00 – 6.30	AECO
Fixed – Sell	May 2010	2,500 MMBtu/d	US$5.79	NYMEX
Collar – Sell	Calendar 2010	1,000 GJ/d	Cdn$5.50 – 7.00	AECO
Fixed – Sell	Calendar 2010	3,000 GJ/d	Cdn$6.19	AECO
Fixed – Sell	Calendar 2010	2,000 GJ/d	Cdn$5.05	AECO
Fixed – Sell	Calendar 2010	2,000 GJ/d	Cdn$5.05	AECO
Sold call	January to February 2011	15,000 MMBtu/d	US$7.00	NYMEX
Sold call	January to March 2011	5,000 MMBtu/d	US$6.60	NYMEX
Fixed – Buy	April 2011	2,500 MMBtu/d	US$5.97	NYMEX

The financial derivative contracts are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income and comprehensive income:

	Years Ended December 31	
	2009	2008
Realized gain (loss) on financial derivative contracts	$ 80,818	$ (60,101)
Unrealized (loss) gain on financial instruments	(54,810)	119,917
Gain on financial derivative contracts	$ 26,008	$ 59,816

Subsequent to December 31, 2009, the Trust added the following commodity derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Sell	February to December 2010	1,000 bbl/d	US$85.50	WTI

Natural Gas	Period	Volume	Price/Unit	Index
Sold call	March 2011	3,000 MMBtu/d	US$6.25	NYMEX
Sold call	July to December 2011	3,000 MMBtu/d	US$6.25	NYMEX

Physical Delivery Contracts

At December 31, 2009, the Trust had the following physical delivery contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
WCS Blend	January to June 2010	1,500 bbl/d	WTI less US$10.75
WCS Blend	January to June 2010	1,500 bbl/d	WTI $\times$ 84.50%
WCS Blend	January to June 2010	1,000 bbl/d	WTI less US$12.45
WCS Blend	January to June 2010	1,000 bbl/d	WTI $\times$ 83.12%
LLK Blend	February to September 2010	500 bbl/d	WTI less US$10.25
LLK Blend	February to September 2010	500 bbl/d	WTI $\times$ 86.85%
WCS Blend	July to December 2010	1,000 bbl/d	WTI less US$14.08
WCS Blend	July to December 2010	1,000 bbl/d	WTI $\times$ 81.06%
WCS Blend	July to December 2010	500 bbl/d	WTI less US$13.15
WCS Blend	Calendar 2010	2,500 bbl/d	US$51.04
Condensate	Calendar 2010	575 bbl/d	WTI plus US$2.25 – 2.60
WCS Blend	Calendar 2010	1,500 bbl/d	WTI less US$14.50
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.74
WCS Blend	Calendar 2010	1,000 bbl/d	WTI $\times$ 83.27%
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.50
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.25
WCS Blend	Calendar 2010	1,000 bbl/d	WTI $\times$ 84.00%
WCS Blend	Calendar 2010	500 bbl/d	WTI $\times$ 84.00%
WCS Blend	Calendar 2010	500 bbl/d	WTI less US$13.29
WCS Blend	Calendar 2010	1,000 bbl/d	WTI less US$13.00

Natural Gas	Period	Volume	Price/Unit
Price collar	Calendar 2010	5,000 GJ/d	AECO Cdn$5.00 – 6.28
Price collar	Calendar 2011	2,500 GJ/d	AECO Cdn$5.50 – 7.10

Subsequent to December 31, 2009, the Trust added the following physical delivery contracts:

Heavy Oil	Period	Volume	Weighted Average Price/Unit
LLB Blend	April to June 2010	500 bbl/d	WTI less US$10.00
LLB Blend	April to June 2010	500 bbl/d	WTI $\times$ 87.40%
LLB Blend	July to September 2010	500 bbl/d	WTI less US$10.25
LLB Blend	July to September 2010	500 bbl/d	WTI $\times$ 87.20%

Natural Gas	Period	Volume	Price/Unit
Fixed – Sell	February to November 2011	2500 GJ/d	AECO Cdn$5.03

Liquidity Risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional trust units. As at

December 31, 2009, the Trust had available unused bank credit facilities in the amount of $198 million, net of working capital deficiency.

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

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	$ 180,493	$ 180,493	$ –	$ –	$ –
Distributions payable to unitholders	19,674	19,674	–	–	–
Bank loan(1)	265,088	265,088	–	–	–
Long-term debt(2)	150,000	–	–	–	150,000
Convertible debentures(2)	7,815	7,815	–	–	–
	$ 623,070	$ 473,070	$ –	$ –	$ 150,000

(1) The bank loan is a 364-day revolving loan with the ability to extend the term.
(2) Principal amount of instruments.

Credit Risk

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

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

As at December 31, 2009, accounts receivable included an $8.5 million balance over 90 days (December 31, 2008 – $9.9 million), of which $2.7 million pertains to drilling credits receivable from the Alberta Minister of Finance. A balance of $2.3 million (December 31, 2008 – $2.4 million) has been set up as allowance for doubtful accounts.

19. COMMITMENTS AND CONTINGENCIES

At December 31, 2009, the Trust had operating leases and processing and transportation obligations as summarized below:

	Total	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Beyond 5 years
Operating leases	$ 40,014	$ 3,408	$ 3,838	$ 3,821	$ 3,684	$ 3,815	$ 21,448
Processing and transportation agreements	7,708	4,328	2,949	302	100	29	–
Total	$ 47,722	$ 7,736	$ 6,787	$ 4,123	$ 3,784	$ 3,844	$ 21,448

At December 31, 2009, the Trust had the following power contracts:

Power	Period	Volume	Price/Unit
Fixed – Buy	March 2009 to June 30, 2010	0.6 MW/hr	Cdn$76.89
Fixed – Buy	Calendar 2010	0.1 MW/hr	Cdn$49.43
Fixed – Buy	Calendar 2010	0.2 MW/hr	Cdn$48.93

Subsequent to December 31, 2009 the Trust added the following power contracts:

Power	Period	Volume	Weighted Average Price/Unit
Fixed – Buy	February to June 2010	0.1 MW/hr	Cdn$44.22
Fixed – Buy	June to December 2010	0.2 MW/hr	Cdn$49.11
Fixed – Buy	June to December 2010	0.2 MW/hr	Cdn$50.33
Fixed – Buy	January to December 2011	0.2 MW/hr	Cdn$47.71

Other

During 2009, the Company implemented an Income Tracking Unit ("ITU") Plan. Liabilities incurred under this plan are settled in cash on predetermined dates, contingent upon attainment of prescribed payment conditions, including the participant's service status with the Company and the intrinsic value of reference incentive rights. Liabilities are recorded when the likelihood of the prescribed payment conditions being met can be reasonably estimated. At December 31, 2009, a $0.1 million liability was accrued.

At December 31, 2009, there were no outstanding letters of credit. At December 31, 2008 there were outstanding letters of credit aggregating $2.3 million issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, the Company became liable for contingent consideration whereby an additional amount would be payable by the Company if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase; therefore, such consideration is recognized only when the contingency is resolved. As at December 31, 2009, additional payments totaling $7.2 million have been paid under the agreement and recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement; therefore, no accrual has been made.

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

20. CAPITAL DISCLOSURES

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

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP measure which is the sum of monetary working capital (being current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative contracts gains or losses)), the principal amount of long-term debt and the balance sheet value of the convertible debentures. At December 31, 2009, total net monetary debt was $474.3 million.

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

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

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

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

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

On December 4, 2008, the Minister of Finance announced changes to the Guidelines to allow an income trust to accelerate the utilization of the safe harbour amounts for each of 2009 and 2010 so that the safe harbour amounts for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for an income trust, but it allows an income trust to use its safe harbour amount remaining as of December 4, 2008 in a single year, rather than staging a portion of the safe harbour amount over the 2009 and 2010 years.

For the Trust, the safe harbour amounts were approximately $730 million for 2006/2007 and approximately $365 million for each of the subsequent three years with any unused amount carrying forward to the next year. The Trust did not issue equity in excess of its safe harbour amounts during 2006, 2007, 2008 or 2009. The Trust issued $165.9 million in equity during the year ended December 31, 2009, resulting in an unused available safe harbour amount of $1,160.7 million as at December 31, 2009. The Trust is planning to complete a conversion transaction from the current trust structure to a corporate legal form to be completed before the end of 2010.

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

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The significant differences between Canadian and United States GAAP ("U.S. GAAP"), as applicable to these consolidated financial statements and notes, are described below. In addition to the significant differences described within, presentation of the following additional disclosures are required under U.S. GAAP and Regulation S-X of the United States Securities and Exchange Commission ("SEC") or specified in Item 18 of the Form 20-F.

Reconciliation of Net Income under Canadian GAAP to U.S. GAAP

		Years Ended December 31	
	Note	2009	2008
Net income – Canadian GAAP		$ 87,574	$ 259,894
Increase (decrease) under U.S. GAAP:			
Depletion, depreciation and accretion	A,B	72,721	(695,715)
Interest, net	M,D	3,174	959
Financing charges	B	3,631	–
Unit-based compensation	J	(92,627)	(1,206)
Income tax (expense) recovery	K	(34,541)	160,235
Non-controlling interest	G	–	3,358
Net income (loss) – U.S. GAAP		$ 39,932	$ (272,475)
Net income (loss) per trust unit	O		
Basic		$ 0.38	$ (2.94)
Diluted		$ 0.38	$ (2.94)
Weighted average trust units	O		
Basic		104,894	92,554
Diluted		106,419	92,554

Condensed Consolidated Statements of Operations – U.S. GAAP

	Note	Years Ended December 31 2009	2008
Revenue			
Petroleum and natural gas sales, net of royalties	L	$ 659,105	$ 952,196
Gain on financial derivative contracts	C	26,008	59,816
		685,113	1,012,012
Expenses			
Operating	J	176,706	174,445
Transportation and blending		159,354	218,706
General and administrative	J	120,620	36,647
Interest	M	29,511	31,553
Financing charges	B	1,865	450
Foreign exchange (gain) loss		(22,824)	37,746
Depletion, depreciation and accretion	A,B	164,495	919,615
		629,727	1,419,162
Income (loss) before taxes		55,386	(407,150)
Income tax expense (recovery)			
Current		11,370	10,177
Future	K	4,084	(144,852)
		15,454	(134,675)
Net income (loss)		39,932	(272,475)
Other comprehensive loss			
Foreign currency translation adjustment	I	(3,951)	–
Comprehensive income (loss)		$ 35,981	$ (272,475)

Consolidated Statements of Accumulated Deficit

Deficit, beginning of the year		$ (1,206,793)	$(1,159,401)
Net income (loss)		39,932	(272,475)
Distributions to unitholders	H	(164,040)	(244,481)
Adjustment for fair value of temporary equity	G	(1,302,397)	469,564
Deficit, end of the year		$ (2,633,298)	$(1,206,793)

Condensed Consolidated Balance Sheets – U.S. GAAP

		As at December 31			
		2009		2008	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets	C,Q	$ 179,539	$ 179,539	$ 173,561	$ 173,561
Future income tax asset	K	418	418	–	–
Financial derivative contracts	C	2,541	2,541	–	–
Petroleum and natural gas properties	A,E	3,943,850	3,843,644	3,648,431	3,548,224
Accumulated depletion & depreciation	A	(2,280,098)	(3,002,832)	(2,047,414)	(2,844,948)
Petroleum and natural gas properties, net		1,663,752	840,812	1,601,017	703,276
Deferred charges	B	–	3,501	–	2,059
Future income tax asset	K	–	4,338	–	–
Goodwill		37,755	37,755	37,755	37,755
		$ 1,884,005	$ 1,068,904	$ 1,812,333	$ 916,651
Liabilities and Unitholders' Equity					
Current liabilities	C,D,F,Q	$ 486,324	$ 486,403	$ 415,776	$ 390,418
Long-term debt		150,000	150,000	217,273	220,362
Convertible debentures	D	–	–	10,195	10,398
Asset retirement obligations		54,593	54,593	49,351	49,351
Share-based payment liability	J	–	91,430	–	21,825
Future income tax liability	A,E,K	179,673	749	192,411	–
Financial derivative contracts		1,418	1,418	–	–
		$ 872,008	$ 784,593	$ 885,006	$ 692,354
Temporary equity	G	–	2,921,560	–	1,431,090
Unitholders' capital	G,H	1,295,931	–	1,129,909	–
Conversion feature of convertible debentures	D	374	–	498	–
Contributed surplus	G,J	20,371	–	21,234	–
Accumulated other comprehensive loss	I	(3,899)	(3,951)	–	–
Deficit		(300,780)	(2,633,298)	(224,314)	(1,206,793)
		1,011,997	(2,637,249)	927,327	(1,206,793)
		$ 1,884,005	$ 1,068,904	$ 1,812,333	$ 916,651

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

	Years Ended December 31	
	2009	2008
Operating activities:		
Net income (loss)	$ 39,932	$ (272,475)
Unit-based compensation	99,070	9,018
Depletion, depreciation and accretion	162,329	918,770
Amortization of deferred charges	2,166	845
Unrealized foreign exchange (gain) loss	(2,889)	42,434
Unrealized loss (gain) on financial derivative contracts	54,810	(119,917)
Future income tax (recovery)	4,084	(144,852)
Realized foreign exchange gain on redemption of long-term debt	(23,685)	–
Change in non-cash working capital	(27,878)	38,857
Asset retirement expenditures	(1,146)	(1,443)
	$ 306,793	$ 471,237
Cash from (used in) financing activities	$ 7,210	$ (217,462)
Cash (used in) investing activities	$ (303,758)	$ (253,775)
Impact of foreign exchange on cash balances	$ (68)	$ –

(A) Full Cost Accounting

Under U.S. GAAP, for determining the limitation of capitalized costs, the carrying value of a cost centre's oil and gas properties cannot exceed the present value of after tax future net cash flows from proved reserves, discounted at 10%, using oil and gas prices based upon an average price in the prior 12-month period and unescalated costs, plus (i) the costs of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation, less (iii) income tax effects related to differences between the book and tax basis of the properties. The amount of the impairment expense is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost centre's petroleum and natural gas properties.

For Canadian GAAP, the carrying value includes all capitalized costs for each cost centre, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. The U.S. GAAP definition under Regulation S-X is similar to Canadian GAAP, except that under U.S. GAAP the carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

The costs of unproved properties included in the petroleum and natural gas properties on the balance sheet date December 31, 2009, which have been excluded from the depletion and ceiling test calculations, by year in which the costs were incurred:

	Total	2009	2008	Prior to 2008
Property acquisitions				
Canada	$ 47,651	$ 2,246	$ 12,003	$ 33,402
USA	76,969	40,338	36,631	–
	$ 124,620	$ 42,584	$ 48,634	$ 33,402

The costs of unproved properties are amortized into the depletion base over five years for Canadian cost centre and three years for the U.S. cost centre. There were no major development projects that were excluded from the capitalized costs being amortized.

Under Canadian GAAP, depletion is calculated by reference to proved reserves estimated using forecast prices. Under U.S. GAAP, depletion is calculated by reference to proved reserves estimated using unescalated prices. The difference in proved reserves has resulted in $81.2 million less depletion recorded under U.S. GAAP for the year ended December 31, 2009 (December 31, 2008 – $104.3 million less depletion).

At December 31, 2009, Baytex's capitalized costs of petroleum and natural gas properties in the Canadian cost centre did not exceed the full cost ceiling under U.S. GAAP. The ceiling test in the U.S. cost centre resulted in a charge of $6.3 million. At December 31, 2008, the Trust's capitalized costs of petroleum and natural gas properties exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $799.1 million charged to depletion, depreciation and accretion ($752.1 million in the Canada cost centre and $47.0 million in the U.S. cost centre). As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

(B) Deferred Charges

Under Canadian GAAP, the Trust elected to expense all financial instrument transaction costs immediately. Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. Under U.S. GAAP, transaction costs continue to be deferred and amortized over the expected term of the related financial asset or liability. Under U.S. GAAP, there is an asset of $3.5 million on the balance sheet as at December 31, 2009 (December 31, 2008 – $2.1 million). Additional amortization expense of $2.2 million has been recognized in net income (December 31, 2008 – $0.8 million) under U.S. GAAP.

(C) Financial Derivative Contracts

Under Section 3855, "Financial Instruments – Recognition and Measurement", physical commodity contracts which are entered into and continue to be held for the purposes of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements are excluded from the requirements of Section 3855 provided the price is not based on a variable that is not closely related to the asset being purchased, sold or used and they are documented as such. Upon the adoption of Section 3855 on January 1, 2007, the Canadian – U.S. GAAP difference has been eliminated and no additional financial asset or liability has been recognized for U.S. GAAP at December 31, 2009 or December 31, 2008.

The Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification ("ASC") 820 – "Fair Value Measurements and Disclosures" (formerly Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements"). This standard defines fair value, establishes a framework for measuring fair value in U.S. GAAP, and expands disclosure about fair value measurements. The Trust adopted these provisions effective January 1, 2008. In June 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures", and upon the Trust's adoption, eliminated the Canadian – U.S. GAAP difference as at December 31, 2009. The implementation of these standards did not have a material impact on the consolidated financial statements.

(D) Convertible Debentures

Under Canadian GAAP, the Trust's convertible debentures are classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete the balance to the principal due on maturity.

Under U.S. GAAP, the convertible debentures in their entirety are classified as debt. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP. As a result $0.4 million has been reclassified to liabilities from equity as at December 31, 2009 (December 31, 2008 – $0.5 million) and $0.1 million of non-cash interest expense has been reversed (December 31, 2008 – $0.1 million).

(E) Step Acquisition on Exchange of Exchangeable shares

Under Canadian GAAP, when the exchangeable shares are exchanged for Trust Units, the transaction is treated as a step acquisition whereby petroleum and natural gas properties are increased by the tax effected difference between the fair value of the exchangeable shares and their carrying value. The offset is credited to future tax liability and Trust units. Under U.S. GAAP the exchangeable shares are considered to be a component of temporary equity and therefore no business combination is considered to have occurred. The cumulative effect of the reversal of the step acquisition is a reduction in petroleum and natural gas properties of $70.4 million (December 31, 2008 – $92.1 million) and a decrease in future tax liability of $20.8 million (December 31, 2008 – $29.1 million).

(F) Bank Loan and Credit Facilities

The weighted average interest rate on short-term borrowings for the year ended December 31, 2009 was 5.66% (December 31, 2008 – 5.39%).

(G) Temporary Equity

The trust units contain a redemption feature which is required for the Trust to retain its mutual fund trust status for Canadian income tax purposes. The redemption feature of the trust units entitles the holder to redeem the Trust Units. However, the restrictions on redemption are not substantive enough to be accounted for as a component of permanent unitholders' equity under U.S. GAAP, in accordance with ASC 480 – "Distinguishing Liabilities from Equity" (formerly, Emerging Issues Task Force ("EITF") D-98 "Classification and Measurement of Redeemable Securities"), the trust units must be presented as temporary equity and recorded on the consolidated balance sheet at their redemption value.

In applying ASC 480, the Trust has recorded temporary equity in the amount of $2,921.6 million as at December 31, 2009 (December 31, 2008 – $1,431.1 million), which represents the estimated redemption value of the trust units and the exchangeable shares (which are convertible into trust units) at the balance sheet date. The difference between the Trust's temporary equity under U.S. GAAP and unitholders' capital under Canadian GAAP is applied to accumulated deficit. The adjustments to accumulated deficit are a debit of $1,302.4 million for December 31, 2009 (December 31, 2008 – credit of $469.6 million).

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

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

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2009 and 2008, there were no exchangeable shares outstanding.

(H) Unitholders' Capital

Distributions declared for the year ended December 31, 2009 were $1.56 per unit (December 31, 2008 – $2.64 per unit). The number of trust units outstanding as at December 31, 2009 was 109,298,911 (December 31, 2008 –

97,685,333). Under U.S. GAAP, the number of trust units issued and outstanding is required to be disclosed on the face of the balance sheet.

Costs related to the issuance of trust units for the year ended December 31, 2009 of $5.1 million (December 31, 2008 – $0.2 million) were netted against unitholders' capital. Under U.S. GAAP, in the consolidated statement of cash flows, these amounts would be presented on a gross basis, whereas under Canadian GAAP, they have been netted against the proceeds from the issuance of trust units.

(I) Other Comprehensive Income

ASC 220 – "Comprehensive Income" (formerly, SFAS No. 130 "Comprehensive Income") requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income. Translation gains and losses are deferred and included in other comprehensive income in unitholders' equity effective January 1, 2009, as discussed in the consolidated financial statements under Canadian GAAP. There are no differences between Canadian and U.S. GAAP.

(J) Unit-Based Compensation

The Trust has a Trust Units Rights Incentive Plan as described in note 13. As the exercise price of the unit rights granted under the plan may be subject to downward revisions from time to time, the unit rights plan is a variable compensation plan under U.S. GAAP. Under ASC 718 – "Compensation – Stock Compensation" (formerly, SFAS No. 123R "Share-Based Payments"), the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan, and unlike Canadian GAAP, must allocate the compensation expense between grants issued to operations and general and administrative staff respectively. The fair value of the unit rights has been determined using a binomial-lattice model. Under ASC 718, the Trust's unit-based compensation plan is classified as a liability and the unit rights are fair valued at each reporting date. Compensation expense for the unit rights plan is recognized in income until settlement date based on the reporting date fair value and the portion of the vesting period that has transpired. The accounting for compensation expense for the unit rights plan results in a difference between Canadian and U.S. GAAP, as the Trust classifies the unit rights plan as equity awards and uses the grant date fair value method to account for its unit compensation expense under Canadian GAAP. Under U.S. GAAP compensation expense was increased by $92.6 million for the year ended December 31, 2009 (December 31, 2008 – increased by $1.2 million). The Trust recorded compensation expense of $99.1 million for the year ended December 31, 2009 (December 31, 2008 – $9.0 million) related to the unit rights granted under the Plan. The allocation between operating and general and administrative expenses under U.S. GAAP for the year ended December 31, 2009 was $13.5 million and $85.6 million respectively (December 31, 2008 – $3.0 million and $18.8 million)

The Trust used the binomial-lattice model to calculate the estimated weighted average grant date fair value of $6.38 per unit for unit rights issued during the year ended December 31, 2009 (December 31, 2008 – $2.42 per unit). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2009	2008
Expected annual exercise price reduction (on rights with declining exercise price)	$1.44 – $2.16	$2.16 – $3.00
Expected volatility	39% – 43%	28% – 39%
Risk-free interest rate	1.78% – 2.72%	2.98% – 4.17%
Forfeiture rate	10%	10%
Expected life of right (years)(1)	Various	Various

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

The following table is a summary of the status of the unvested unit rights as of December 31, 2009 and 2008 and changes during the years then ended:

	Number of unvested rights	Weighted average grant date fair value
Unvested, December 31, 2007	4,645	$ 3.99
Granted	2,838	$ 2.42
Vested	(2,149)	$ 3.96
Forfeited	(665)	$ 4.12
Unvested, December 31, 2008	4,669	$ 3.03
Granted	1,844	$ 6.38
Vested	(2,227)	$ 3.38
Forfeited	(114)	$ 3.00
Unvested, December 31, 2009	**4,172**	**$ 4.32**

As of December 31, 2009, there was $36.0 million of total unrecognized compensation cost related to unvested unit rights; the cost is expected to be recognized over a weighted average period of 1.4 years. The total fair value of unit rights vested during the year ended December 31, 2009 was $37.0 million (December 31, 2008 – $8.3 million).

The intrinsic value of a unit right is the amount by which the current market value of the underlying trust unit exceeds the exercise price of the unit right.

The following table summarizes information related to unit rights activity during the years ended December 31, 2009 and 2008:

	Number of rights	Weighted average exercise price[1]	Weighted average remaining contract life (years)	Aggregate intrinsic value
Outstanding, December 31, 2008	8,449	$ 14.58	3.3	$ 16,277
Granted	1,844	$ 24.87	4.7	–
Exercised	(2,059)	$ 9.97	1.5	29,468
Forfeited	(114)	$ 16.43	3.2	508
Outstanding, December 31, 2009	**8,120**	**$ 16.68**	**3.1**	**$ 105,720**
Exercisable, December 31, 2009	**3,948**	**$ 13.22**	**2.1**	**$ 65,078**
Expected to vest	**3,755**	**$ 19.96**	**4.0**	**$ 36,578**

(1) Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.

	Number of rights		Weighted average exercise price(1)	Weighted average remaining contract life (years)		Aggregate intrinsic value
Outstanding, December 31, 2007	7,662	$	14.67	3.4	$	35,553
Granted	2,838	$	19.27	4.7		–
Exercised	(1,386)	$	7.69	1.1		23,109
Forfeited	(665)	$	21.79	4.1		1,836
Outstanding, December 31, 2008	8,449	$	14.58	3.3	$	16,277
Exercisable, December 31, 2008	3,780	$	11.52	2.3	$	15,858
Expected to vest	4,201	$	17.07	4.1	$	377

(1) *Exercise price reflects the grant price less the reduction in exercise price as discussed above. During the year, the Trust modified the terms of certain unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the trust units on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per unit right from $16.49 to $16.68.*

(K) Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate current and future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the Reconciliation of Net Income under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheets – U.S. GAAP include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The implementation of ASC 740 – "Income Taxes" (formerly, FASB Interpretation Number ("FIN") 48) did not result in any adjustment to the beginning tax positions of the Trust. The unrecognized tax benefits of the Trust are disclosed below.

Unrecognized tax benefits, January 1, 2008	$	4,250
Gross decrease for tax positions taken during a prior period		98
Gross decrease for tax positions taken during the current period		(195)
Gross increase for tax positions taken during the current period		447
Reductions due to lapse of applicable statute of limitations		(1,000)
Unrecognized tax benefits, December 31, 2008	$	3,600
Gross increase for tax positions taken during a prior period		61
Gross decrease for tax positions taken during a prior period		–
Gross decrease for tax positions taken during the current period		(566)
Reductions due to lapse of applicable statute of limitations		(175)
Unrecognized tax benefits, December 31, 2009	**$**	**2,920**

All of the Trust's unrecognized tax benefits at December 31, 2009, if recognized, would affect the Trust's effective income tax rate. The Trust does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.

The Trust recognizes interest and penalties related to uncertain tax positions in a component of interest expense. During each of the years ended December 31, 2009 and 2008, interest expense includes $0.3 million of interest related to taxation amounts. There are no accruals of interest and penalties as at December 31, 2009 on the balance sheet (December 31, 2008 – accrued $nil).

Baytex and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax, or the relevant income tax in other international jurisdictions. Baytex may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the date of mailing of the original notice of assessment in respect of any particular taxation year. For the Canadian federal and provincial income tax matters, the open taxation years range from 2003 to 2009. The U.S. federal statute of limitations for assessment of income tax is generally closed for the taxation years through 2004. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. The tax authorities have not audited any of the income tax returns of Baytex or its subsidiaries for the open taxation years noted above.

(L) Petroleum and Natural Gas Revenues

Under U.S. GAAP, petroleum and natural gas revenues are required to be presented net of royalties, excise and sales taxes to governments and other mineral interest owners.

(M) Interest

Under U.S. GAAP, interest income should be disclosed separately from interest expense on the face of the income statement. For the year ended December 31, 2009, interest income netted against the interest expense was $0.1 million (December 31, 2008 – $0.2 million).

(N) Business Combinations

Under ASC 805 – "Business Combinations" (formerly, SFAS 141, "Business Combinations"), supplemental pro forma disclosure is required for significant business combinations occurring during the year. On June 4, 2008 the Trust completed a business combination that was deemed a significant acquisition. The following unaudited pro forma information provides an indication of what the Trust's results of operations might have been under U.S. GAAP had the business combination taken place on January 1, 2008:

(unaudited)	2008 Pro Forma
Petroleum and natural gas sales	$ 1,196,599
Net (loss)	$ (281,457)
Net (loss) per trust unit:	
Basic	$ (2.96)
Diluted	$ (2.96)

(O) Earnings Per Share

Under Canadian GAAP, basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged and convertible debentures were converted. Under U.S. GAAP, since the exchangeable shares are classified in the same manner as the trust units, basic net income per unit is calculated based on net income divided by weighted average units and the unit equivalent of the outstanding exchangeable shares.

(P) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

(Q) Additional Disclosures

1. The components of accounts receivable are as follows:

As at December 31	2009	2008
Petroleum and natural gas sales and accrual	$ 107,657	$ 62,926
Joint venture	28,581	23,755
Prepaid, deposits and other	3,252	3,280
Less: allowance for doubtful accounts	(2,336)	(2,410)
	$ 137,154	$ 87,551

2. The components of inventory are as follows:

As at December 31	2009	2008
Petroleum and condensates	$ 1,217	$ 72
Other	167	260
	$ 1,384	$ 332

3. The components of accounts payable and accrued liabilities are as follows:

As at December 31	2009	2008
Trade payables	$ 81,387	$ 64,067
Joint venture	23,564	25,670
Petroleum and natural gas accrued liabilities	63,500	66,361
Other	12,042	8,255
	$ 180,493	$ 164,353

(R) Commitments and Contingencies

For the year ended December 31, 2009, the Trust recorded an expense for operating leases of $2.9 million (December 31, 2008 – $2.8 million). The operating leases have expiration dates ranging from April 2010 to April 2020.

(S) Supplemental Information

Change in Non-Cash Working Capital Items

For the years ended December 31	2009	2008
Operating activities		
Accounts receivable	$ (39,565)	$ 29,795
Crude oil inventory	(1,052)	5,665
Accounts payable and accrued liabilities	12,689	3,397
Foreign exchange on working capital	50	–
	(27,878)	38,857
Investing activities		
Accounts receivable	(10,038)	–
Accounts payable and accrued liabilities	3,451	19,874
	(6,587)	19,874
	$ (34,465)	$ 58,731

(T) Recent Developments in U.S. Accounting

In August 2009, the FASB issued Accounting Standards Update ("ASU") 2009-05 – "Fair Value Measurements and Disclosures (Topic 820) – Measuring Liabilities at Fair Value" ("ASU 09-05"), which became effective the first reporting period (including interim periods) beginning after issuance. ASU 09-05 requires entities to measure the fair value of liabilities using one or more of several prescribed valuation techniques within the ASU when quoted prices in an active market for the identical liability are not available. The ASU also clarifies that: entities are not required to include separate inputs or adjustments to other inputs relating to the existence of restrictions that prevent the transfer of liabilities when estimating their fair value; and quoted prices in active markets for identical liabilities at the measurement date and the quoted prices for identical liabilities traded as assets in active markets when adjustments to the quoted prices of assets are required are Level 1 fair value measurements. The adoption of this standard did not have a material impact on the Trust's financial statements.

In June 2009, the FASB issued ASU 2009-01 ("ASU 09-01") "Topic 105 – Generally Accepted Accounting Principles" (formerly, SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles"). This standard became effective for interim and annual periods ending after September 15, 2009. The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. GAAP. The adoption of this standard did not have a material impact on the consolidated financial statements of the Trust.

In May 2009, the FASB issued ASC 855 "Subsequent Events" (formerly, SFAS No. 165, "Subsequent Events"), which establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. The guidance was effective for interim or annual periods ending after June 15, 2009. The adoption of this guidance did not have a material impact on the consolidated financial statements of the Trust.

In March 2009, the FASB issued ASC 815 "Derivatives and Hedging" (formerly, SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities") effective January 1, 2009. The standard requires qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of gains and losses on derivative contracts and details of credit-risk-related contingent features in those derivative contracts. The standard also requires disclosure of the financial statement location and amounts of derivative instruments in the applicable financial statement for each interim and annual reporting period. The disclosures required by this new standard are located in note 18 and did not have a material impact on our results of operations or financial position.

In January 2009, the FASB issued ASC 805 "Business Combinations" (formerly, SFAS 141(R), "Business Combinations", which replaced SFAS 141), which requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard may have an impact on the Trust's U.S. GAAP accounting for future business combinations.

In January 2009, the FASB issued ASC 810 "Consolidation" (formerly, SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51"), which requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP Consolidated Statement of Earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the non-controlling interest and to disclose these respective amounts. The adoption of this standard did not have a material impact on the consolidated financial statements of the Trust.

In December 2008, the SEC released Final Rule Release No. 33-8995 "Modernization of Oil and Gas Reporting," subsequently updated with ASU 2010-03 – "Oil and Gas Reserve Estimation and Disclosure" to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report petroleum and natural gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The ruling is effective for disclosures in our Annual Report on Form 40-F for the year ended December 31, 2009. Adoption of the new standard is reflected in the results of future ceiling tests for the Trust.