ENTERRA ENERGY TRUST
Form 20-F
July 15, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

(Mark One)

o **Registration statement pursuant to Section 12(b) or 12(g) of the Securities Exchange Act of 1934.**

or

þ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.**

For the fiscal year ended December 31, 2004.

Or

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.**
For the transition period from to

Commission file number 000-32115

ENTERRA ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Alberta, Canada
(Jurisdiction of Incorporation or Organization)

Suite 2600, 500 4th Avenue S.W.
Calgary, Alberta, Canada
T2P 2V6
(Address of Principal Executive Offices)

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

Title of Each Class	Name of Each Exchange On Which Registered
None	N/A

Securities registered or to be registered pursuant to Section 12(g) of the Act: **Trust Units**

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

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Trust Units, without par value at December 31, 2004: 25,426,800

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 o Item 18 þ

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PART I

ITEM 1. Identity of Directors, Senior Management and Advisors

Not applicable

ITEM 2. Offer Statistics and Expected Timetable

Not applicable

ITEM 3. Key Information

A. Selected Financial Data

The financial data set forth below as at December 31, 2004, 2003, 2002, 2001 and 2000 and for each of the years in the five-year period ended December 31, 2004 have been derived from our audited consolidated financial statements and should be read in conjunction with those financial statements. The financial data has been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP), the application of which, in the case of Enterra Energy Trust, conforms in all material respects for the periods presented with US GAAP, except as disclosed in footnotes to the financial statements.

The following table presents a summary of our consolidated statement of operations derived from our financial statements for the years ended December 31, 2004, 2003, 2002, 2001 and 2000. The monetary amounts in the table are in Canadian dollars (C$). All data presented below should be read in conjunction with ITEM 5 Operating and Financial Review and Prospects and ITEM 18 Financial Statements and accompanying notes included in this Form 20-F.

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Consolidated statements of earnings data:

(In thousands, except per unit data)

	Year Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
	C$	**C$**	**C$**	**C$**	**C$**
		Restated[(1)]	Restated[(1)]	Restated[(1)]	Restated[(1)]
Amounts in accordance with Canadian GAAP					
Revenue	$ 108,293	$ 72,097	$ 25,746	$ 20,264	$ 16,700
Earnings before income taxes	$ 14,953	$ 7,220	$ 5,878	$ 2,423	$ 3,880
Net earnings	$ 14,764	$ 5,098	$ 4,881	$ 1,700	$ 2,256
Basic earnings per unit/share	$ 0.63	$ 0.27	$ 0.27	$ 0.12	$ 0.26
Diluted earnings per unit/share	$ 0.63	$ 0.27	$ 0.26	$ 0.12	$ 0.25
Dividends paid on preferred shares	$	$ 33	$ 23	$	$
Dividends paid on common shares	$	$	$	$	$
Weighted average units/shares outstanding basic	23,561	18,954	18,309	13,985	8,844
Amounts in accordance with US GAAP [(2)]					
Revenue	$ 108,293	$ 72,097	$ 25,746	$ 20,264	$ 16,700
Earnings before income taxes	$ 7,906	$ 12,835	$ 2,909	$ 3,228	$ 4,175
Net earnings (loss)	$ (179,632)	$ (218,914)	$ 6,748	$ (15,535)	$ 2,453
Basic earnings (loss) per unit/share	$ (7.70)	$ (11.55)	$ 0.37	$ (1.11)	$ 0.53
Diluted earnings (loss) per unit/share	$ (7.70)	$ (11.55)	$ 0.36	$ (1.11)	$ 0.52
Dividends paid on preferred shares	$	$ 33	$ 23	$	$
Dividends paid on common shares	$	$	$	$	$

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The following table indicates a summary of our consolidated balance sheets as of December 31, 2004, 2003, 2002, 2001 and 2000. The monetary amounts in the table are in Canadian dollars (C$).

Consolidated balance sheet data:

(In thousands)

	As at December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
	C$	**C$**	**C$**	**C$**	**C$**
		Restated(1)	Restated(1)	Restated(1)	Restated(1)
Amounts in accordance with Canadian GAAP					
Cash	$ 4,779	$ 66	$ 108	$ 43	$ 1
Accounts receivable and prepaid expenses	$ 16,131	$ 9,204	$ 7,971	$ 6,880	$ 2,505
Property and equipment	$ 146,910	$ 105,253	$ 96,142	$ 74,130	$ 19,588
Total assets	$ 200,301	$ 116,661	$ 104,505	$ 81,054	$ 23,354
Total Unitholders equity	$ 98,095	$ 47,629	$ 38,417	$ 33,410	$ 7,173
Amounts in accordance with US GAAP (2)					
Cash	$ 4,779	$ 66	$ 108	$ 43	$ 1
Accounts receivable and prepaid expenses	$ 16,131	$ 9,204	$ 7,971	$ 6,880	$ 2,505
Property and equipment	$ 117,940	$ 84,288	$ 68,308	$ 43,693	$ 18,085
Total assets	$ 171,331	$ 95,696	$ 76,670	$ 50,616	$ 22,076
Total Mezzanine equity	$ 529,764	$ 261,810	$	$	$
Total Unitholders equity	$ (449,727	$ (227,813)	$ 23,373	$ 16,373	$ 7,545

(1) Effective January 1, 2004, the Trust retroactively adopted CICA Handbook Section 3110 Asset Retirement Obligations . The new recommendations require the recognition of the fair value of obligations associated with the retirement of long-lived assets to be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense, which are included in depletion, depreciation, and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

(2) For further information on the US GAAP reconciliation, see ITEM 18 Financial Statements Note 17.

NON-GAAP ITEMS

Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. It is management s view, based on its communications with investors during events like conference calls, webcasts or road shows, that cash flow from operations is most relevant to our investors and unitholders, especially since the Trust s conversion to an oil and gas income trust. Cash flow from operations is extremely relevant to investors because it is the starting point for setting the monthly distribution level. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, (GAAP) and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow and cash flow from operations throughout this report are based on cash flow before changes in non-cash working capital.

The calculation of barrels of oil equivalent (boe) is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content and does not represent a value equivalency at the wellhead. BOEs may be misleading, particularly if used in isolation

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements. All statements other than statements of historical facts contained in this report, including statements regarding our future financial position, estimated amounts and timing of capital expenditures, royalty rates and exchange rates, plans for drilling, exploration and development, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words believe, may, will, estimate, continue, anticipate, intend, should, plan, expect and similar expressions, as they relate t intended to identify forward-looking statements. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends that we believe may affect our financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions described in Risk Factors and elsewhere in this report.

Statements concerning oil and gas reserves contained in this report may be deemed to be forward-looking statements as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions.

These risks and uncertainties include:

- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and
- market demand;
- risks and uncertainties involving geology of oil and gas deposits;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;

- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing; and
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld.

Other sections of this report may include additional factors that could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for our management to predict all risk factors, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

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We undertake no obligation to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. We cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

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Exchange Rate Information

We publish our consolidated financial statements in Canadian dollars. In this report, except where otherwise indicated, all dollar amounts are stated in Canadian dollars. References to $ or C$ are to Canadian dollars and references to US$ are to U.S. dollars. The following table sets forth for each period indicated the period end exchange rates for conversion of U.S. dollars to Canadian dollars, the average exchange rates on the last day of each month during such period and the high and low exchange rates during such period. These rates are based on the noon buying rate in New York City, expressed in U.S. dollars, for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York. The exchange rates are presented as Canadian dollars per $1.00. On June 15, 2005, the noon buying rate was US$1.00 equals Cdn.$1.2397 and the inverse noon buying rate was Cdn.$1.00 equals US$0.8067.

U.S. Dollar/Canadian Dollar Exchange Rates for Five Most Recent Financial Years

Year Ended December 31,	**2004**	**2003**	**2002**	**2001**	**2000**
End of period	0.8300	0.7738	0.6344	0.6285	0.6669
Average for the period	0.7683	0.7139	0.6372	0.6456	0.6732
High during the period	0.8502	0.7738	0.6656	0.6714	0.6969
Low during the period	0.7164	0.6349	0.6175	0.6227	0.6410

U.S. Dollar/Canadian Dollar Exchange Rates for Previous Six Months

	December 2004	January 2005	February 2005	March 2005	April 2005	May 2005
High	0.8447	0.8333	0.8161	0.8331	0.8265	0.8081
Low	0.8053	0.8102	0.7962	0.8037	0.7945	0.7874

B. Capitalization and Indebtedness

Not applicable

C. Reasons for the Offer and Use of Proceeds

Not applicable

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D. Risk Factors

Certain risk factors that could materially adversely affect our cash flow, operating results, financial condition or the business of our operating subsidiaries are set out below. Investors should carefully consider these risk factors before making investment decisions involving our trust units.

Our results of operations and financial condition are dependent on the prices received for our oil and natural gas production.

Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of oil and natural gas reserves. Any resulting decline in our cash flow could reduce distributions.

We use financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from changes in natural gas and oil commodity prices. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, our commodity hedging activities could expose us to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect or our hedging policies and procedures are not followed. Furthermore, we cannot guarantee that such hedging transactions will fully offset the risks of changes in commodities prices.

In addition, we regularly assess the carrying value of our assets in accordance with Canadian generally accepted accounting principles under the full cost method. If oil and natural gas prices become depressed or decline, the carrying value of our assets could be subject to downward revision.

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce distributions to Unitholders as well as affect the market price of the trust units.

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

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

Distributions may be reduced during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our trust units.

To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow that the Trust receives that is available for distribution to Unitholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and, as a consequence, the amount of cash available to distribute to Unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The board of directors of Enterra Energy Corp., the principal operating subsidiary of the Trust, has the discretion to determine the extent to which cash flow from Enterra will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the credit facility. As a consequence, the amount of funds retained by Enterra to pay debt service charges or reduce debt will reduce the amount of cash available for distribution to Unitholders during those periods in which funds are so retained.

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A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the price that we received for our production, which in turn, could reduce distributions to Unitholders as well as affect the market price of our trust units.

Our business depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could reduce distributions to our Unitholders.

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our trust units as well as distributions to Unitholders.

The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price. We could be subject to unfavorable price changes to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

If we are unable to acquire additional reserves, the value of our trust units and distributions to Unitholders may decline.

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

Actual reserves will vary from reserve estimates, and those variations could be material, and affect the market price of our trust units and distributions to Unitholders.

The reserve and recovery information contained in the independent engineering report prepared by McDaniel & Associates Consultants Ltd. (McDaniel) relating to our reserves is only an estimate and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by McDaniel.

The value of our trust units depends upon, among other things, the reserves attributable to our properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve figures contained herein are only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;

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production decline rates;

ultimate recovery of reserves;

success of future development activities;

marketability of production;

effects of government regulation; and

other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates.

As we expand our operations beyond oil and natural gas production in western Canada, we face new challenges and risks.

If we were unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our trust units and distributions to Unitholders.

Our operations and expertise have been focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. Recently, we acquired oil and gas properties outside this geographic area which are also non-conventional assets, being coal bed methane. In addition, the Trust Indenture does not limit the activities to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas presents challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

In determining the purchase price of acquisitions, we rely on both internal and external assessments relating to estimates of reserves that may prove to be materially inaccurate. Such reliance could adversely affect the market price of our trust units and distributions to Unitholders.

The price we are willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves we acquire may be less than expected, which could adversely impact cash flows and distributions to Unitholders. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

We do not operate some of our properties and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our trust units and distributions to Unitholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2004, approximately 5% of our daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements, which govern the properties not operated by us, typically require the operator to conduct operations in a good and workmanlike manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners, such as Unitholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or willful misconduct.

Delays in business operations could adversely affect distributions to Unitholders and the market price of our trust units.

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In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Unitholders in a given period and expose us to additional third party credit risks.

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of the distributions that are paid to Unitholders, and could affect the market price of our trust units.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduce amounts available for distribution to Unitholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Unitholders. The agreements governing our credit facility provide that if we are in default under the credit facility, exceed certain borrowing thresholds or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to make distributions to Unitholders may be restricted.

Our lenders have been provided with a security interest in substantially all of our assets. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may foreclose on and sell the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to Unitholders.

Our current credit facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under our existing credit facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. Our current credit facility consists of a revolving operating demand loan, and a demand subordinated debt facility. Repayment of all outstanding amounts may be demanded at any time. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to Unitholders may be materially reduced.

If we do not satisfy the conditions under the Kingsbridge Purchase Agreement, we will be unable to draw down on the committed equity financing facility with Kingsbridge. The potential unavailability of this facility might negatively affect our financing activities.

Under the terms of the Kingsbridge Purchase Agreement, we may, at our sole discretion, sell to Kingsbridge, and Kingsbridge would be obligated to purchase, Trust Units for up to US$100 million in proceeds to us. We may not sell Trust Units to Kingsbridge, however, unless we satisfy the conditions of the Kingsbridge Purchase Agreement which are described under The Committed Equity Financing Facility with Kingsbridge. The price at which we may sell Trust Units under the Kingsbridge Purchase Agreement is based on a discount to the volume weighted

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average market price of the Trust Units for fifteen trading days following each of our elections to sell Trust Units. For each election, we select the lowest threshold price at which our Trust Units may be sold, but the threshold price cannot be lower than US$11.04 per share. We also may not sell any Trust Units with respect to any day in the fifteen day pricing period in which the price at which Trust Units would be sold under the facility is less than 85% of the volume weighted average trading price of the Trust Units during the previous five trading days. If the market price of our Trust Units falls below US$12.00 per Trust Unit, which after giving effect to the discount would result in a price per Trust Unit lower than the US$11.04 minimum threshold price, or with respect to any period in which the price at which Trust Units would be sold is less than the 85% of the volume weighted average trading price for the five previous trading days, the committed equity financing facility will not be an available source of financing.

Our agreement with Kingsbridge permits Kingsbridge to terminate the committed equity financing facility if Kingsbridge determines that a material and adverse event has occurred affecting our business, operations, properties or financial condition, or if any situation occurs that would interfere with our ability to perform any of our obligations under the agreement.

If we are unable to draw down on the committed equity financing facility, and are otherwise unable to obtain capital from other sources on a timely basis or on terms favorable to us, we may be required to fail to take advantage of acquisitions or other opportunities, scale back our operations, or sell some of our assets.

Each advance under the committed equity financing facility is limited. We may not draw down on the committed equity financing facility when Kingsbridge beneficially owns in excess of 9.9% of our outstanding Trust Units. The potential unavailability of this facility might negatively affect our financing activities.

The first draw down under the committed equity financing facility is limited to US$10 million. Each draw down election we make thereafter is limited to a maximum of 4% of our market capitalization at the time of the election, and cannot in any case exceed US$25 million. We must also wait at least five trading days after the end of a fifteen trading day draw down period before we can commence the next draw down. In addition, the committed equity financing facility limits the beneficial ownership of Kingsbridge to 9.9% of our outstanding Trust Units, which percentage includes any Trust Units purchased pursuant to the committed equity financing facility or that we may issue to Kingsbridge as liquidated damages, or that may be issued upon exercise of the Kingsbridge Warrant. Depending on the market price of our Trust Units and Kingsbridge s other holdings of our Trust Units, this restriction may limit the maximum amount we can draw down under the committed equity financing facility. If Kingsbridge s beneficial ownership were to exceed 9.9% of our outstanding Trust Units, together with the total amount of our Trust Units that would be outstanding upon completion of a draw down, we would not be able to draw down on the committed equity financing facility until such time as Kingsbridge sells enough Trust Units of our Trust Units or our number of Trust Units outstanding increases, which may not occur. Therefore, we may not be able to draw down on the full US$100 million commitment. The 9.9% limitation on Kingsbridge s beneficial ownership will not prevent Kingsbridge from selling some of its holdings and then receiving additional Trust Units, such that the total number of Trust Units that we may sell to Kingsbridge under the committed equity financing facility that it may resell under this prospectus is greater than 9.9% of our outstanding Trust Units.

There are a large number of Trust Units underlying the committed equity financing facility and otherwise that are being registered in this report, and the sale or availability for sale of these Trust Units may depress the price of our Trust Units.

To the extent that Kingsbridge sells Trust Units issued under the committed equity financing facility under this prospectus, our Trust Unit price may decrease due to the additional selling pressure in the market. The perceived risk of dilution from sales of Trust Units to or by Kingsbridge or otherwise pursuant to this report may cause holders of our Trust Units to sell their Trust Units, which could contribute to a decline in our Trust Unit price.

The sale of Trust Units underlying the committed equity financing facility could encourage short sales by third parties, which could contribute to the future decline of our Trust Unit price.

A significant downward pressure on the price of our Trust Units caused by the sale of material amounts of Trust Units under the committed equity financing facility could encourage short sales by third parties. In a short sale, a prospective seller borrows Trust Units from a unitholder or broker and sells the borrowed Trust Units. The prospective seller hopes that the Trust Unit price will decline, at which time the seller can purchase Trust Units at a lower price to repay the lender. The seller profits when the Trust Unit price declines because it is purchasing Trust Units at a price lower than the sale price of the borrowed Trust Units. Such sales could place downward pressure on the price of our Trust Units by increasing the number of Trust Units being sold, which could contribute to the future decline of our Trust Unit price.

We cannot predict the actual number of Trust Units that we will issue under the committed equity financing facility, in any particular draw down, or in total or otherwise under this report. The number of Trust Units we will issue under each draw down under the committed equity financing facility will fluctuate based on the market price of Trust Units over the fifteen trading days after we give a draw down notice for each draw down period.

The actual number of Trust Units that we will issue under the committed equity financing facility in any particular draw down, and in total, is uncertain. Subject to the limitations in our agreement with Kingsbridge, we have the discretion to draw down funds at any time throughout the term of the committed equity financing facility, and we have not determined the amount of proceeds, if any, we will seek to raise through the committed equity financing facility. Also, the number of Trust Units we must issue after giving a draw down notice will fluctuate based on the market price of our Trust Units over the fifteen trading days after we give a draw down notice, and Kingsbridge will receive more Trust Units if our Trust Unit price declines.

During each fifteen trading day draw down period, Kingsbridge is permitted to sell the Trust Units to be issued with respect to each trading day once the discount purchase price for such day (and therefore the number of Trust Units to be purchased for such day) is determined. These permitted sales during a draw down period may cause the volume weighted average price of our Trust Units to decline on immediately subsequent days, resulting in the sale of additional Trust Units to Kingsbridge on immediately subsequent days for the same monetary proceeds to us. The further sale of Trust Units priced on those immediately subsequent days could then cause further price declines on later days, resulting in the sale of increasing number of Trust Units for the same monetary proceeds as the draw down period progresses.

Furthermore, Kingsbridge s 9.9% beneficial ownership limitation is determined on, and based on the amount of our Trust Units outstanding on, each settlement date. As the Trust Units outstanding on each settlement date increases, Kingsbridge may be required to purchase more Trust Units during a draw down period than would have been apparent on the date that we sent the draw down notice to Kingsbridge.

The committed equity financing facility imposes certain liquidated damages, which may impair our liquidity and ability to raise capital.

The terms of the committed equity financing facility require us to pay liquidated damages in the event that a registration statement is not available for the resale of securities purchased by Kingsbridge under the committed equity financing facility. These liquidated damages provisions generally require us to pay an amount based on the decline in value, if any, of Trust Units held by Kingsbridge during the time a registration statement is unavailable. See The Committed Equity Financing Facility with Kingsbridge for a further description of these liquidated damages provisions. The liquidated damages could adversely affect our liquidity, or to the extent we are permitted to and decide to pay such damages through the issuance of Trust Units, cause significant dilution to holders of our Trust Units.

We have a working capital deficiency at December 31, 2004; our credit facilities can be called at any time. Any material change in our liquidity could impair our ability to pay dividends and could adversely affect the value of your investment.

Our credit facilities are classified as a short-term liability on our balance sheet as they are on a demand basis and may be called at any time. Accordingly, at December 31, 2004, we had a working capital deficiency of $ 42.4 million, which means our current liabilities exceeded our current assets by that amount. Although we are not subject to and do not expect to make principal repayments under our current banking arrangement, they could be called for repayment at any time. Other than in the event of a default or a breach of covenants, we do not expect to make any principal payments in 2005, except for those required to stay within the limits of our decreasing subordinated debt facility.

Our assets are leveraged. Any material change in our liquidity could impair our ability to pay dividends and could adversely affect the value of your investment.

We carry debt that is secured by our assets. A decrease in the amount of our production or the price we receive for it could make it difficult for us to service our debt or may cause the bank that issued our loan to determine that our assets are insufficient security for our bank debt.

The oil and natural gas industry is highly competitive.

We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our trust units and distributions to Unitholders.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.

Our operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to Unitholders.

The operation of oil and natural gas wells could subject us to environmental claims and liability.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of clean up orders. Legislation regulating the oil and natural gas industry may be changed to impose higher standards and potentially more costly obligations. For example, the 1997 Kyoto Protocol to the United Nation s Framework Convention on Climate Change, known as the Kyoto Protocol, was ratified by the Canadian government in December 2002 and will require, among other things, significant reductions in greenhouse gases. The impact of the Kyoto Protocol on us is uncertain and may result in significant additional costs (future) for our operations. Although we record a provision in our financial statements relating to our estimated future environmental and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future environmental and reclamation obligations.

We are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of cash flow and, therefore, will reduce the amounts available for distribution to Unitholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Lower crude oil and natural gas prices increase the risk of ceiling limitation write-downs. Any write-downs could materially affect the value of your investment.

We changed our method of accounting for petroleum and natural gas properties from the successful efforts method to the full cost method in 2001. All costs related to the exploration for and the development of oil and gas reserves are capitalized into a single cost center representing Enterra s activity, which is undertaken exclusively in

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Canada. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells. Proceeds from the disposal of properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a major change in the depletion rate.

Capitalized costs are depleted and depreciated using the unit-of-production method based on the estimated gross proven oil and natural gas reserves before royalties as determined by independent engineers. Units of natural gas are converted into barrels of equivalents on a relative energy content basis.

Effective January 1, 2004, we prospectively adopted new Canadian accounting standards relating to full cost accounting for oil and gas entities. The new standard modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proven reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There was no write down of the Trust s property and equipment as at January 1, 2004 as a result of adopting the standard.

Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test using estimated future net revenue from proven oil and gas reserves using a discount factor of 10%. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001 Enterra realized a U.S. GAAP ceiling test write-down of Cdn.$17.5 million, after tax. At December 31, 2004 Enterra realized a U.S. GAAP ceiling test write-down of Cdn.$6.3 million, after tax.

The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are low or volatile. We may experience additional ceiling test write-downs in the future.

Unforeseen title defects may result in a loss of entitlement to production and reserves.

Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, distributions to Unitholders may be reduced.

Aboriginal Land Claims.

The economic impact on us of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada. We are unable to assess the effect, if any, that any such claim would have on our business and operations.

Changes in tax and other laws may adversely affect Unitholders.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Unitholders. The Department of Finance (Canada) has indicated that it will continue to evaluate the development of the income trust market as part of its ongoing monitoring and assessment of Canadian financial markets and the Canadian tax system. Accordingly, changes in this area are possible.

Income Tax Matters.

On October 31, 2003, the Department of Finance (Canada) released, for public comment, proposed amendments to the Tax Act that relate to the deductibility of interest and other expenses for income tax purposes for taxation years commencing after 2004. In general, the proposed amendments may deny the realization of losses in respect of a business if there is no reasonable expectation that the business will produce a cumulative profit over the period that the business can reasonably be expected to be carried on. If such proposed amendments were enacted and successfully invoked by the CRA against the Trust or a subsidiary entity, it could materially adversely affect the amount of distributable cash available. However, Enterra believes that it is reasonable to expect the Trust and each subsidiary entity to produce a cumulative profit over the expected period that the business will be carried on.

Expenses incurred by Enterra are only deductible to the extent they are reasonable. Although the Trust is of the view that all expenses to be claimed by the Trust and its subsidiary entities should be reasonable and deductible, there can be no assurance that CRA will agree. If CRA were to successfully challenge the deductibility of such expenses, the return to Unitholders may be adversely affected.

The Trust Indenture provides that an amount equal to the taxable income of the Trust will be payable each year to Unitholders in order to reduce the Trust s taxable income to zero. Where in a particular year, the Trust does not have sufficient available cash to distribute such an amount to Unitholders, the Trust Indenture provides that additional trust units must be distributed to Unitholders in lieu of cash payments. Unitholders will generally be required to include an amount equal to the fair market value of those trust units in their taxable income, notwithstanding that they do not directly receive a cash payment.

As noted above, the Department of Finance (Canada) has indicated that it will continue to evaluate the development of the income trust market as part of its ongoing monitoring and assessment of Canadian financial markets and the Canadian tax system. Accordingly, changes in this area are possible. Such changes could result in the income tax considerations described under the heading Canadian Federal Income Tax Considerations being materially different in certain respects.

There would be material adverse tax consequences if the Trust lost its status as a mutual fund trust under Canadian tax laws.

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

The Trust would be taxed on certain types of income distributed to Unitholders. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.

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

The trust units would not constitute qualified investments for Registered Retirement Savings Plans, or RRSPs , Registered Retirement Income Funds, or RRIFs , Registered Education Savings Plans, or RESPs , or Deferred Profit Sharing Plans, or DPSPs . If, at the end of any month, one of these exempt plans holds trust units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the trust units at the time the trust units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified trust units would be subject to taxation on income attributable to the trust units. If an RESP holds non-qualified trust units, it may have its registration revoked by the CRA.

In addition, we may take certain measures in the future to the extent we believe them necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of trust units.

Rights as a unitholder differ from those associated with other types of investments.

The trust units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Trust. The trust units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the trust units does not provide Unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring oppression or derivative actions. The unavailability of these statutory rights may also reduce the ability of Unitholders to seek legal remedies against other parties on our behalf.

The trust units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The trust units will have minimal value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, cash distributions do not represent a yield in the traditional sense as they represent both return of capital and return on investment and the distributions received over the life of the investment may not meet or exceed the initial capital investment.

Changes in market-based factors may adversely affect the trading price of our trust units.

The market price of our trust units is primarily a function of anticipated distributions to Unitholders and the value of our properties. The market price of our trust units is therefore sensitive to a variety of market-based factors, including, but not limited to, interest rates and the comparability of our trust units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the trust units.

Our operations are entirely independent from the Unitholders and loss of key management and other personnel could impact our business.

Unitholders are entirely dependent on the management of Enterra with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to our oil and natural gas properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Trust. Investors should carefully consider whether they are willing to rely on the existing management before investing in the trust units.

There may be future dilution.

One of our objectives is to continually add to our reserves through acquisitions and through development. Since we do not reinvest a material portion of our cash flow, our success is, in part, dependent on our ability to raise capital from time to time by selling additional trust units. Unitholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of trust units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of trust units to effect acquisitions.

There may not always be an active trading market for the trust units.

While there is currently an active trading market for our trust units in the United States and Canada, we cannot guarantee that an active trading market will be sustained.

The limited liability of Unitholders is uncertain.

By virtue of the enactment of the *Income Trusts Liability Act* (Alberta) on July 1, 2004, Unitholders of the Trust (as an Alberta income trust) are now suppose to be protected from liabilities of the Trust to the same extent that a shareholder is protected from liabilities of a corporation but this protection only applies in respect of any act, default, obligation or liability of the Trust or any of the trustees thereof which arose or occurred after July 1, 2004. Notwithstanding the legislation, Unitholders may not be protected from certain liabilities of the Trust, in particular, those which arose or occurred on or prior to July 1, 2004. Accordingly, a Unitholder could be held personally liable for obligations of the Trust in respect of contracts or undertakings which the Trust has entered into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the Unitholders and a limitation of liability to Trust property, such protective provisions may not operate to avoid unitholder liability. Further, although the Trust has agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the Unitholder resulting from or arising out of that Unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse Unitholders for any such liability.

The redemption rights of Unitholders are limited.

Unitholders have a limited right to require the Trust to repurchase their trust units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The Trust s ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed in specie to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

Taxation of Enterra.

Enterra is subject to taxation in each taxation year on its income for the year, after deducting interest paid to the Trust on the Notes. During the period that Exchangeable Shares issued by Enterra are outstanding, a portion of the cash flow from operations will be subject to tax to the extent that there are not sufficient resource pool deductions, capital cost allowance or utilization of prior years non-capital losses to reduce taxable income to zero. Enterra intends to deduct, in computing its income for tax purposes, the full amount available for deduction in each year associated with its income tax resource pools, undepreciated capital cost (UCC) and non-capital losses, if any. If there are not sufficient resource pools, UCC and non-capital losses carried forward to shelter the income of Enterra, then cash taxes would be payable by Enterra. In addition, there can be no assurance that taxation authorities will not seek to challenge the amount of interest expense relating to the Notes. If such a challenge were to succeed against Enterra, it could materially adversely affect the amount of cash flow available for distribution to Unitholders.

Further, interest on the Notes accrues at the Trust level for income tax purposes whether or not actually paid. The Trust Indenture provides that an amount equal to the taxable income of the Trust will be distributed each year to Unitholders in order to reduce the Trust s taxable income to zero. Where interest payments on the Notes are due but not paid in whole or in part, the Trust Indenture provides that any additional amount necessary to be distributed to Unitholders may be distributed in the form of Units rather than in cash. Unitholders will be required to include such additional amount in income even though they do not receive a cash distribution.

We may undertake acquisitions that could limit our ability to manage and maintain our business, result in adverse accounting treatment and are difficult to integrate into our business. Any of these events could result in a material change in our liquidity, impair our ability to pay dividends and could adversely affect the value of your investment.

A component of future growth will depend on the ability to identify, negotiate, and acquire additional companies and assets that complement or expand existing operations. However we may be unable to complete any acquisitions, or any acquisitions we may complete may not enhance our business. Any acquisitions could subject us to a number of risks, including:

diversion of management s attention;

inability to retain the management, key personnel and other employees of the acquired business;

inability to establish uniform standards, controls, procedures and policies;

inability to retain the acquired company s customers;

exposure to legal claims for activities of the acquired business prior to acquisition; and inability to integrate the acquired company and its employees into our organization effectively.

Since we are a Canadian company and most of our assets and key personnel are located in Canada, you may not be able to enforce a U.S. judgment for claims you may bring against us, our assets, our key personnel or many of the experts named in this report. This may prevent you from receiving compensation to which you would otherwise be entitled.

We have been organized under the laws of Alberta, Canada and the majority of our assets are located outside the U.S. In addition, a majority of the members of our Board of Directors and our officers and many of the experts named in this report are residents of countries other than the U.S. As a result, it may be impossible for you to effect service of process upon us or these individuals within the U.S. or to enforce any judgments in civil and commercial matters, including judgments under U.S. federal securities laws. In addition, a Canadian court may not permit you to bring an original action in Canada or to enforce in Canada a judgment of a U.S. court based upon civil liability provisions of the U.S. federal securities laws.

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ITEM 4. Information on the Trust

A. History and development of The Trust

Enterra Energy Trust (the Trust and, together with its direct and indirect subsidiaries and partnerships, we , our or us is an open ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture dated as of October 24, 2003, between Enterra Energy Corp. and Olympia Trust Company (the Trust Indenture). The registered office of the Trust is located at Suite 3300, 421 7th Avenue S.W., Calgary, Alberta, T2P 4K9 and its head office is located at Suite 2600, 500-4th Avenue S.W., Calgary, Alberta T2P 2V6; phone 403-263-0262.

As a result of the completion of a plan of arrangement involving the Trust, Enterra Energy Corp. (Old Enterra), Enterra Acquisition Corp. and Enterra Energy Commercial Trust (EEC Trust or Commercial Trust) (the Arrangement) on November 25, 2003, former holders of common shares of Old Enterra received two trust units or two Exchangeable Shares of Enterra Acquisition Corp., in accordance with the elections made by such holders, and Old Enterra became a subsidiary of the Trust. Old Enterra was subsequently amalgamated with Enterra Acquisition Corp. to form Enterra Energy Corp. (New Enterra).

The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

We make monthly cash distributions to Unitholders from our net cash flow. Our primary sources of cash flow are interest payments from Enterra, and Rocky Mountain Acquisition Corp (RMAC) of interest on the Notes and payments from EEC Trust of principal and interest on the CT Notes.

Olympia Trust Company has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the outstanding trust units. The principal and head office of Olympia Trust Company is located at 2300, 125 9th Avenue S.E., Calgary, Alberta T2G 0P6.

Enterra

Enterra is the principal operating subsidiary of the Trust. Enterra was formed on the amalgamation of Enterra Acquisition Corp., Big Horn Resources Ltd., Enterra Sask. Ltd. and Old Enterra on November 25, 2003 pursuant to the Arrangement and is governed by the laws of the Province of Alberta. EEC Trust is the sole holder of voting shares of Enterra. All of the crude oil and natural gas properties and related assets in which the Trust has an interest are held, directly or indirectly, through Enterra, RMAC and Rocky Mountain Gas Inc. (RMG).

RMAC

Rocky Mountain Acquisition Corp. is a corporation created under the laws of Alberta and is another operating subsidiary of the Trust in addition to Enterra. RMAC was created by the amalgamation of a predecessor corporation (Old RMAC) with Rocky Mountain Energy Corp. (RME). Old RMAC was incorporated for the purpose of acquiring RME and immediately following such acquisition, Old RMAC and RME were amalgamated to form RMAC. EEC Trust is the sole holder of voting shares of RMAC. All of the crude oil and natural gas properties and related assets in which the Trust has an interest are held, directly or indirectly, through Enterra, RMAC and RMG.

EUSA

Enterra US Acquisitions Inc. (EUSA) is a corporation incorporated under the laws of Washington for the purpose of acquiring RMG. EUSA is an indirect subsidiary of EEC Trust.

RMG is a corporation incorporated under the laws of Wyoming. RMG was acquired effective June 1, 2005 and holds coal bed methane assets in Wyoming and Montana. All of the crude oil and natural gas properties and related assets in which the Trust has an interest are held, directly and indirectly, through Enterra, RMAC and RMG.

The Partnership

Enterra Production Partnership (the Partnership) was formed as a general partnership under the laws of the Province of Alberta on August 16, 2001. The Partnership currently holds a significant portion of our producing crude oil and natural gas properties from which we ultimately derive our cash flow. The partners of the Partnership are Enterra (as to 99.99%) and Partnerco (as to 0.01%).

EEC Trust

Enterra Energy Commercial Trust is a commercial trust governed by the laws of the Province of Alberta. The Trust holds 100% of the issued and outstanding trust units of EEC Trust. EEC Trust holds 100% of the issued and outstanding common shares of Enterra and RMAC.

History

Old Enterra (formerly Westlinks Resources Ltd.) was organized on June 30, 1998 by the statutory amalgamation of Temba Resources Ltd. and PTR Resources Ltd. pursuant to the provisions of the *Business Corporations Act* (Alberta). Temba Resources Ltd. was incorporated in Alberta on July 31, 1996. Immediately prior to the amalgamation, which created Old Enterra, Temba Resources Ltd., amalgamated with its wholly owned subsidiary, Rainee Resources Ltd. PTR Resources Ltd. was incorporated in Alberta on September 18, 1992 as 542275 Alberta Ltd., changed its name to Ablevest Holdings Ltd. on June 14, 1993, and to PTR Resources Ltd. on December 1, 1997.

In 1998, Old Enterra acquired a non-operated working interest averaging approximately 20% in a Dina sand oil pool located in the Sounding Lake area of Alberta, consisting of 1,270 acres and approximately 35 producing wells.

In September 1999, Old Enterra acquired a 94% working interest in four producing oil wells and a saltwater disposal well in the Sylvan Lake area of Alberta.

In May 2000, Old Enterra acquired, effective January 1, 2000, further working interests in the Sounding Lake area of Alberta, consisting of a further 36% working interest in the Dina sand oil pool as well as working interests averaging approximately 91% in 21 producing oil wells. The purchase price for such interests was $11,900,000.

On November 15, 2000, Old Enterra sold, effective October 1, 2000, all of its interests in the Bigoray area of Alberta for cash consideration of $4,494,500. Proceeds from the sale were used to reduce Old Enterra s bank debt and to fund its 2001 acquisition program.

On December 6, 2000, Old Enterra acquired a 25% working interest in a producing gas well in the Altares area of northeast British Columbia for cash consideration of $1,000,000.

On January 17, 2001, Old Enterra completed a secondary public offering in the United States of 1,000,000 units, each unit consisting of one common share and one share purchase warrant, for U.S. $4.55 per unit. The share purchase warrants were exercisable for six months at U.S. $4.50 per share. Net proceeds from the offering were used for Old Enterra s 2001 acquisition and drilling program.

On February 28, 2001, Old Enterra entered into a farm-out and option agreement whereby it was granted the ability to earn an interest in over 12,000 acres of land in the Altares region of northeast British Columbia. Under the terms of the farm-out and option agreement, Old Enterra was obligated to drill a minimum of two wells and had an option to drill up to four more wells to earn an interest in all of the lands.

On March 27, 2001, Old Enterra acquired an average 67% working interest in 8,705 gross acres of land and 34 producing oil wells in the Grand Forks area of southern Alberta for cash consideration of $5,500,000. The effective date of the acquisition was January 1, 2001.

On April 23, 2001, Old Enterra entered into the EuroGas Agreement. On June 5, 2001, Old Enterra completed the acquisition of an aggregate of 8,275,500 Big Horn shares from EuroGas.

On June 12, 2001, Old Enterra entered into an agreement with a private company to acquire certain oil and gas assets in the Superb area of Saskatchewan. The purchase price for the assets was $2,800,000, which amount was satisfied by the payment of $1,500,000 in cash and through the issuance of Common Shares. Through this acquisition, Old Enterra acquired a 91% working interest in four existing Waseca heavy oil wells with a combined production rate of approximately 180 bbls/d.

Effective August 16, 2001, Westlinks and Big Horn Resources Ltd. entered into an agreement under Section 192 of the *Canada Business Corporations Act*, whereby Big Horn shareholders were issued Westlinks common shares and options in exchange for Big Horn common shares and options. Big Horn was incorporated under the laws of the Province of Saskatchewan on February 16, 1960 as Contact Gold Mines Ltd. On July 7, 1969, Big Horn changed its name to Contact Ventures Ltd. Big Horn was continued under the *Business Corporations Act* (Saskatchewan) on December 28, 1979 and subsequently continued under the *Canada Business Corporations Act* on September 9, 1982. On April 15, 1988, Big Horn changed its name to West Pride Industries Corp. and on April 2, 1991 Big Horn consolidated its common shares on a 4 for 1 basis. Effective September 7, 1993 Big Horn further consolidated its common shares on a 7 for 1 basis and changed its name to Big Horn Resources Ltd.

Effective December 10, 2001, Westlinks Resources Ltd. (i.e., Old Enterra) changed its name to Enterra Energy Corp.

On March 26, 2002, Old Enterra redeemed 6,123,870 of its Series I Preferred Shares for $2,300,000, resulting in a gain of $2,905,290.

On April 12, 2002, Old Enterra was granted a 30-day extension for the 1,000,000 share purchase warrants which were exercisable until April 17, 2002. The expiry date was extended to May 17, 2002. The warrants expired on May 17, 2002 without being exercised.

On October 8, 2002, Old Enterra raised $5 million for a sale-leaseback arrangement on some of its production equipment.

Old Enterra received $18.3 million in 2003 as proceeds on the sale of miscellaneous non-core properties. These proceeds were applied to reduce bank debt and improve working capital.

On June 20, 2003, Old Enterra s common shares commenced trading on the Toronto Stock Exchange under the symbol ENT . They were previously trading on the TSX Venture Exchange.

On August 5, 2003, Old Enterra announced its intention to reorganize itself into an oil and gas income trust.

On September 30, 2003, Old Enterra redeemed all 611,803 outstanding Series I Preferred Shares for $520,032.

On October 27, 2003 The American Stock Exchange began trading in options in Old Enterra under the symbol EMU

Old Enterra s plan of arrangement in respect of the reorganization of Old Enterra into Enterra Energy Trust received overwhelming approval at the special shareholder meeting held on November 24, 2003. Shareholders voted 99.37% in favor of the arrangement resolution. The transaction also received the approval of the Court of Queen s Bench of Alberta on November 24, 2003. The transaction became effective on November 25, 2003. The trust units of Enterra Energy Trust commenced trading on the Nasdaq National Market System under EENC and the Toronto Stock Exchange under ENT.UN on Friday November 28, 2003. After the transaction, the Trust had a total of 18,951,556 trust units issued and outstanding. In addition, Enterra had a total of 2,000,000 exchangeable shares issued and outstanding.

On January 16, 2004 the Trust entered into a financing agreement whereby it issued 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$16,500,000. The funds received from this financing were applied to pay down debt and for corporate general purposes. The financing closed on June 29, 2004.

On January 30, 2004 Enterra closed the acquisition from an unrelated oil and gas company, of properties in Central Alberta. The purchase price after final adjustments was C$19,609,000. Upon closing, the acquisition added 1,800 boe/d of net production, consisting of 1,600 bbl/d of oil and 1,200 mcf/d of gas along with 22,166 gross acres of undeveloped land.

On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs). Funds received were used to repay debt.

In June 2004, Enterra sold a small producing property in Provost area of Central Alberta with proven reserves of 55.2 Mboe for C$263,366.

In August 2004, Enterra sold a non-producing well in the Sylvan Lake area of Central Alberta for C$400,000.

On September 29, 2004, the Trust, through its subsidiary RMAC, completed the acquisition of RME by way of a plan of arrangement whereby RMAC acquired all of the issued and outstanding shares of RME. The transaction was valued at approximately C$55 million. RME shareholders received approximately 85% of the consideration in the form of Trust Units or Exchangeable Shares and 15% in cash. The Trust issued 1,946,576 Trust Units and 341,882 Exchangeable Shares. The acquisition of RME added approximately 1,000 boe/d of production to the Trust together with the potential to drill 22 additional wells.

On April 22, 2005, the Trust entered into a committed equity financing facility with Kingsbridge Capital Limited, pursuant to which Kingsbridge committed, subject to certain significant limitations and conditions precedent, to purchase up to US$100 million of Trust Units.

On May 30, 2005, the Trust and High Point Resources Inc. entered into an arrangement agreement for the acquisition by the Trust of all of the issued and outstanding common shares of High Point. The acquisition is to be completed by way of a plan of arrangement pursuant to which shareholders of High Point will receive for each share of High Point held 0.105 of a trust unit of the Trust. The closing price of the Trust Units on Friday, May 27th was C$25.41, valuing the common shares of High Point at C$2.67 per share. High Point has approximately 85 million shares outstanding. The transaction, including assumption of High Point s debt of approximately US$67 million, has been valued at approximately US$250 million. The Trust will be issuing approximately 8.9 million units or approximately 34% of the total number of Trust Units currently outstanding.

On June 1, 2005, the acquisition of Rocky Mountain Gas, Inc. closed. RMG holds natural gas assets in Montana and Wyoming. A portion of the Wyoming assets currently generates net/net production of approximately 2.2 million BTU s per day. RMG has approximately 130,000 net acres of production rights to coal bed methane. The consideration consisted of US$14 million by the issuance of exchangeable shares (exchangeable on a one-to-one basis into Trust Units), US$5.5 million by the issuance of Trust Units and US$0.5 million in cash, which was paid as a deposit when the acquisition agreement was signed.

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B. Business Overview

Enterra Energy Trust operates as an oil and gas income trust. For the year ended December 31, 2004, our production averaged 6,957 boe/d and our proved and probable reserves were approximately 9.4 MBOE. We pay monthly cash distributions on the 15th day of each month to Unitholders of record on the immediately preceding distribution record date. This amount was set at US$0.10 per unit for the first three distributions. The following table sets forth the amount of monthly cash distributions paid per Trust Unit by the Trust since the completion of the Arrangement.

	Distribution per Trust Unit (US$)	
December, 2003[1]	$	0.10
January, 2004	$	0.10
February, 2004	$	0.10
March, 2004	$	0.11
April, 2004	$	0.11
May, 2004	$	0.11
June, 2004	$	0.12
July, 2004	$	0.12
August, 2004	$	0.12
September, 2004	$	0.13
October, 2004	$	0.13
November, 2004	$	0.13
December, 2004	$	0.14
January, 2005	$	0.14
February, 2005	$	0.14
March, 2005	$	0.15
April, 2005	$	0.15
May, 2005	$	0.15
June, 2005	$	0.16

Note:

(1) This distribution was the first cash distribution of the Trust following the completion of the Arrangement.

Our growth will come mainly from future acquisition of properties to replenish our reserves. These acquisitions will be financed in part with additional debt and with the issuance of trust units.

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Business Strategy

Our business strategy is to grow our oil and gas reserves and distributions by acquiring properties that provide additional oil and gas production and potential for development upside. We are focused on per unit growth. We will finance acquisitions with debt and equity, the optimal mix being one that minimizes Unitholders dilution while maintaining a strong balance sheet. Our ability to replace and grow our reserves over time is the key success factor in our business strategy.

Revenues

Our revenue is obtained from the sale of oil and natural gas. The revenues for the last three years were:

	For the year ended December 31,		
($000 s)	2004	2003	2002
Revenue	$ 108,293	$ 72,097	$ 25,746

The business is not seasonal in nature. We produce the oil and gas and then sell the oil and gas to marketing companies and integrated oil and gas companies that then arrange for the oil and gas to be further refined and processed and they sell the refined products to the ultimate end users.

Employees

At December 31, 2004, we and JED had collectively, 76 employees and consultants working in the Calgary head office and in field operations.

Under the Technical Services Agreements with JED, effective January 1, 2004, JED provides certain staff to Enterra while Enterra provides offices and other administrative services to JED. As consultants to Enterra, JED s employees will be eligible to participate in benefit plans of Enterra, if any.

Office Facilities

We currently lease 20,927 square feet of office space at Suite 2600, 500 4th Avenue S.W. in Calgary, Alberta in a lease that commenced November 1, 2001. The lease has a term expiring on December 31, 2009 and the annual rental is currently C$29.64 per square foot (including operating costs and property taxes). We originally leased space in a different Calgary office building but all of this space is subleased to third parties and the lease expires on August 31, 2006.

Competition

The petroleum industry is highly competitive. We compete with numerous other participants in the acquisition of oil and gas leases and properties, and the recruitment of employees. Any company can make acquisitions and bid on provincial leases in Alberta. Competitors include oil companies and other income trusts, many of whom have greater financial resources, staff and facilities than we have. Our ability to increase reserves in the future will depend not only on our ability to develop existing properties, but also on our ability to select and acquire suitable additional producing properties or prospects for drilling. We also compete with numerous other companies in the marketing of oil. Competitive factors in the distribution and marketing of oil include price and methods and reliability of delivery.

Government Regulation in Canada

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

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principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada, or NEB. Any oil export to be made pursuant to a contract of longer duration, to a maximum of 25 years, requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

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

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

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

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

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better-targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from

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qualifying for the program. Such rules will not presently preclude Enterra from being eligible for the ARTC program.

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

Land Tenure

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

Environmental Regulation

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

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act*, or EPEA, which came into force on September 1, 1993. The EPEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties for violations. We are committed to meeting our responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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Additional Information Relating to the Trust

Income Streams and Distribution Policy

A portion of the cash flows generated by the assets held, directly or indirectly, by the Trust is distributed to holders of trust units. The Trustee may, in respect of any period, declare payable to the Unitholders all or any part of the net income of the Trust.

The Enterra Board currently intends to provide all Unitholders with monthly cash distributions of approximately USD 80% of available cash flow from operations. However, the availability of cash flows for the payment of distributions will at all times be dependant upon a number of factors, including resource prices, production rates and reserve growth and the Enterra Board cannot assure that cash flows will be available for distribution to Unitholders in the amounts anticipated or at all. See *Risk Factors* .

We make monthly cash distributions to Unitholders from our net cash flow. Our primary sources of cash flow are interest payments from Enterra, and Rocky Mountain Acquisition Corp (RMAC) of interest on the Notes and payments from EEC Trust of principal and interest on the CT Notes.

The Notes

Pursuant to the Arrangement, Enterra issued the Series A notes to the Trust (the Series A Notes). The principal amount of the Series A Notes issued is $125,000,000. The Series A Notes are unsecured and bear interest from the date of issue at 14% per annum. Interest is payable for each month during the term on the 15th day of the month following such month. Enterra also issued other notes to the Trust in 2004 in the amount of $36,679,530, bearing interest at 11%. RMAC issued Series A notes, as well as other notes, to the Trust in 2004 in the aggregate amount of $40,113,607, bearing interest at 11%.

CT Note

The CT Note is a subordinated, demand participating promissory note. The CT Note may bear interest at a rate that can be re-set from time to time so as to approximate the taxable income of the EEC Trust.

Trust Units

An unlimited number of trust units may be created and issued pursuant to the Trust Indenture. Each trust unit entitles the holder thereof to one vote at any meeting of the holders of trust units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All trust units rank among themselves equally and rateably without discrimination, preference or priority. Each trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the trust units held by such holder (see "*Redemption Right*) and to one vote at all meetings of Unitholders for each trust unit held. In addition, in certain circumstances Unitholders will have the right to instruct the trustees of EEC Trust with respect to the voting of shares of Enterra held by EEC Trust at meetings of holders of shares of Enterra. See *Meetings of Unitholders* and *Exercise of Voting Rights* .

The trust units do not represent a traditional investment and should not be viewed by investors as shares in either Enterra, or the Trust. As holders of trust units in the Trust, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions.

The price per trust unit is a function of anticipated distributable income generated by the Trust and the ability of the Trust to effect long-term growth in the value of the Trust. The market price of the trust units is sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire additional assets. Changes in market conditions may adversely affect the trading price of the trust units.

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

Special Voting Rights

The Trust Indenture allows for the creation of Special Voting Rights which will enable the Trust to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by Enterra or other subsidiaries of the Trust in connection with other exchangeable share transactions.

Holders of Special Voting Rights are not be entitled to any distributions of any nature whatsoever from the Trust and each holder shall be entitled to attend at meetings of Unitholders and, subject to the terms of the instrument creating the Special Voting Rights, is entitled to that number of votes equal to the number of votes attached to the trust units for which the Special Voting Rights held by such holder are exchangeable, exercisable or convertible. Holders of Special Voting Rights are also be entitled to receive all notices, communications or other documentation required to be given or otherwise sent to holders of trust units. Except for the right to attend and vote at meetings of Unitholders and receive notices, communications and other documentation sent to Unitholders, the Special Voting Rights do not confer upon the holders thereof any other rights.

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued a Special Voting Right to the Voting and Exchange Trust Agreement Trustee for the benefit of every person who received Exchangeable Shares pursuant to the Arrangement. Some of these Exchangeable Shares still remain outstanding.

Unitholder Limited Liability

The Trust Indenture provides that no unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust or its obligations or affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust s assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a unitholder from or arising as a result of such unitholder not having such limited liability. The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the foregoing, Unitholders of the Trust may not be protected from certain liabilities of the Trust. See *Risk Factors* .

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

Redemption Right

Trust units are redeemable at any time on demand by the holders thereof upon delivery to the transfer agent of the Trust of the certificate or certificates representing such trust units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem trust units by the transfer agent, the holder thereof shall only be entitled to receive a price per trust unit (the Market Redemption Price) equal to the lesser of: (i) 90% of the market price of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Where more than one market exists for the trust units, the principal market shall mean the market on which the trust units experience the greatest volume of trading activity on the date or for the period in question, as applicable.

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

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their trust units is subject to the limitation that the total amount payable by the Trust in respect of such trust units and all other trust units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that Enterra may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of trust units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series A Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Series A Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall (herein referred to as Redemption Notes). Notwithstanding the foregoing, the distribution of any Series A Notes and the issuance of any Redemption Notes shall be conditional upon the receipt of all necessary regulatory approvals and the making of all necessary governmental registrations, declarations and filings, including, without limitation, any required registration of the Series A Notes or Redemption Notes, as applicable, to be distributed or issued in respect of the payment of the Market Redemption Price, and any required qualification of the Trust Indenture relating to such Series A Notes or Redemption Notes, under the securities laws of the United States.

If at the time trust units are tendered for redemption by a unitholder, (i) the outstanding trust units are not listed for trading on the TSX or Nasdaq and are not traded or quoted on any other stock exchange or market which Enterra considers, in its sole discretion, provides representative fair market value price for the trust units, or (ii) trading of the outstanding trust units is suspended or halted on any stock exchange on which the trust units are listed for trading or, if not so listed, on any market on which the trust units are quoted for trading, on the date such trust units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such trust units were tendered for redemption then such unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per trust unit (the Appraised Redemption Price) equal to 90% of the fair market value thereof as determined by Enterra as at the date on which such trust units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Series A Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Series A Notes or Redemption Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Series A Notes or Redemption Notes. Series A Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of

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amendments to the Trust Indenture (except as described under Amendments to the Trust Indenture), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by (i) Enterra or (ii) the holders of trust units and Special Voting Rights holding in aggregate not less than 5% of the votes entitled to be voted at a meeting of Unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxy holder need not be a unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding trust units shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Rights who are present at the meeting shall be regarded as representing outstanding trust units equivalent in number to the votes attaching to such Special Voting Rights.

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

Voting Of EEC trust units

There will be a meeting of the holders of EEC trust units immediately following each meeting of Unitholders for the purpose of permitting the Trustee to vote the EEC trust units held by the Trust in the manner directed by Unitholders at the immediately preceding meeting of the Trust. Any resolution passed by Unitholders pertaining to the manner in which EEC trust units held by the Trust are to be voted by the Trustee in respect of a particular matter which is to be put forth to the holders of EEC trust units for vote at a contemplated meeting (including by written resolution) of holders of EEC trust units, shall be deemed to be a direction to the Trustee in respect of the EEC trust units held by the Trust to, as applicable, either vote such EEC trust units in favor of or in opposition to, or to vote or with-hold from voting in respect of such matter in equal proportions to the votes cast by Unitholders in respect of the matter, and the Trustee is obligated to vote, in respect of such matter if put forth to the holders of EEC trust units at a meeting of such holders, the EEC trust units held by the Trust in accordance with such direction.

Exercise of Voting Rights

The Trustee is prohibited from authorizing or approving:

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

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving the Trust and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above; or

(c) the winding up, liquidation or dissolution of the Trust prior to the end of the term of the Trust except in conjunction with an internal reorganization as referred to in paragraph (a) above;

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

In addition, the Trustee is prohibited from authorizing the EEC trustees to approve, or vote any shares of Enterra to approve:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by Enterra, the Trust or the Partnership, except in conjunction with an internal reorganization of the direct or indirect assets of Enterra, EEC Trust or the Partnership, as the case may be, as a result of which EEC Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving Enterra, EEC Trust or the Partnership and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) the winding up, liquidation or dissolution of Enterra, EEC Trust or the Partnership prior to the end of the term of EEC Trust, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

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

(e) any material amendments to the articles of Enterra to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of Enterra s shares in a manner which may be prejudicial to EEC Trust; or

(f) any material amendment to the CT Indenture or the Partnership Agreement which may be prejudicial to EEC Trust;

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

The Trustee is prohibited from authorizing the EEC trustees to vote any shares of Enterra with respect to the election of directors of Enterra, the appointment of auditors of Enterra, or the approval of Enterra s financial statements, without the prior approval of the Unitholders by Ordinary Resolution. Finally, the Trustee is prohibited from authorizing the EEC trustees to vote any shares of Enterra with respect to any matter which under applicable law (including policies of Canadian securities commissions) or applicable stock exchange rules would require the approval of the holders of shares of Enterra by ordinary resolution or special resolution, without the prior approval of the Unitholders by Ordinary Resolution or Special Resolution, as the case may be.

Trustee

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

The initial term of the Trustee s appointment is until the third annual meeting of Unitholders. The Unitholders shall, at the third annual meeting of Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also be removed by Special Resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The Enterra Board has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to Enterra responsibility for any and all matters relating to the following: (i) an offering of securities of the Trust; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities of the Trust; (iii) all matters relating to the content of any offering documents, the accuracy of the

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disclosure contained therein and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of trust units or rights to trust units; (vi) all matters relating to the redemption of trust units; (vii) all matters relating to the voting rights on any instruments held by the Trust, other than the EEC trust units; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of The Trustee

The Trustee, its directors, officers, employees, shareholders and agents is not be liable to any unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, prima facie, properly executed, any depreciation of, or loss to, the property of the Trust incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of Enterra, or any other person to whom the Trustee has, with the consent of Enterra, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by Enterra to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to The Trust Indenture

The Trust Indenture may be amended or altered from time to time by special resolution of the Unitholders. The Trustee may, without the approval of any of the Unitholders, amend the Trust Indenture for, among others, the following purposes:

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

(b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) and paragraph 132(8)(a) of the Tax Act as from time to time amended or replaced;

(c) providing for and ensuring (i) the allocation of items of income, gain, loss, deduction and credit in respect of the Trust for United States federal income tax purposes; (ii) the filing of income tax returns necessary or desirable for the purposes of United States federal income tax; or (iii) compliance by the Trust with any other applicable provisions of United States federal income tax law;

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

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

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

(g) changing the situs of or the laws governing the Trust which, in the opinion of the Trustee, is desirable in order to provide Unitholders with the benefit of any legislation limiting their liability.

Termination of the Trust

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

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trust shall continue in full force and effect for a period which shall end twenty-one years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II. In the event that the Trust is wound up, the Trustee will sell and convert into money the property of the Trust in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the property of the Trust in accordance with any applicable laws or requirements of any governmental agency or authority, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the special resolution of the Unitholders authorizing the termination of the Trust. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their pro rata interests.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders and the unaudited interim financial statements of the Trust will be mailed to Unitholders within the periods prescribed by securities legislation. The year-end of the Trust shall be December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

The Trust is subject to the reporting requirements of the 1934 Act applicable to foreign private issuers, and in connection therewith will file or submit reports, including annual reports and other information with the U.S. Securities and Exchange Commission (the SEC). Such reports and other information can be inspected and copied at the public reference facilities maintained by the SEC at 450 Fifth Street, N.W., Room 1024, Judiciary Plaza, Washington, D.C. The Trust s SEC filings and submissions will also be available to the public on the SEC s web site at http://www.sec.gov.

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C. Organizational Structure

The following diagram depicts the intercorporate relationships among the Trust and its subsidiaries. Reference should be made to Item 4.A of this report for a complete description of our structure.

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D. Property, plants and equipment

The Trust s core areas include the Peace River Arch area of Alberta and Central Alberta in Canada. The Trust also has a large inventory of prospects, the development of which could significantly increase the size of our existing production and reserve base.

Peace River Arch of Alberta, Canada

Clair

The Clair property is located 7 miles north of the city of Grande Prairie, Alberta. Enterra s assets include a 100% working interest in 3,840 acres of land, 23 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the Doe Creek (Dunvegan) formation with a small amount of gas production from the Charlie Lake and Halfway formations. Production is light, 44-degree API gravity crude oil and solution gas from the Doe Creek oil pool. At December 31, 2004 there were 23 oil wells producing a combined 2,860 bbl/d of oil and 910 mcf/d of solution gas on a working interest basis before royalties. One dually completed Charlie Lake and Halfway gas well also produces combined daily gas of 400 mcf/d on a working interest basis before royalties. Enterra has a 100% working interest in this well. To date, Enterra has drilled or re-completed 29 wells for oil and seven wells for water injection. There are no further drilling plans for the pool. Enterra is currently maintaining

100% voidage replacement with minor water flood modifications made in early 2004. The oil production has been maintained since 2003 due to successful modifications to the water flood.

Total proved remaining net proved reserves assigned to the Doe Creek A (Dunvegan) pool are 1,426 mbbl of oil, 912 mmcf of gas and 54 mbbl of natural gas liquids. McDaniel and Associates have stated that the additional reserves associated with the water flood would be moved into the proven category in a staged approach as they have for the last two years. Included in the total net proved reserves of Clair are reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well of 265 mmcf of gas and 16 mbbl of natural gas liquids.

Enterra also owns and operates a central oil treating facility at Clair, which is connected into the Pembina Peace Pipeline system in September 2003.

Hines Creek

The Hines Creek property is located 94 miles north of the city of Grande Prairie, Alberta. Enterra s assets include a 15% working interest in 5,750 gross acres of land and one producing gas well. Two wells were drilled in the first quarter of 2005 and, as this is a winter only drilling area, the remaining two wells will be drilled in 2006.

Total net proved reserves assigned to the Hines Creek property are 368 mmcf of gas.

The gas is transported three miles north through a non-operated pipeline to a main feeder line to a central non-operated facility.

Central Alberta, Canada

Provost

The Provost property is located southwest of the town of Provost, Alberta. Major areas within the package are Alliance, Sounding Lake, Monitor, Provost Cummings Y Unit and Wainwright. Enterra s assets include an average working interest of 70% in 52,000 gross acres of land as well as 245 producing oil wells and 19 producing gas wells. Production is obtained primarily from the Dina, Cummings and Belly River formations. Enterra s share of current production for the entire area is 1,500 bbl/d of oil and 3,050 mcf/d of gas on a working interest basis before royalties. In order to optimize production and lower operating costs, Enterra has and continues to upgrade pump sizes to maximize oil production and upgrade or consolidate oil batteries to handle higher volumes of total fluid and injection water. Solution gas is currently conserved at most of the oil batteries.

Enterra drilled four oil wells in the Cummings Y Unit in 2004 to bring the total number of oil producers to 21. Due to the success of this drilling program, Enterra has decided to drill another nine wells in the Unit for oil production. In order to lower operating costs and optimize reserve recovery from the Cummings Y pool, Enterra is also in the process of constructing a central facility to ship clean oil and re-inject produced water into the pool. Makeup water from several source wells will be used to maintain voidage replacement at 100%.

Enterra was assigned net proved reserves at Provost of 1,569 mbbl of oil, 1,208 mmcf of natural gas and 32 mbbl of natural gas liquids.

Princess/ Tide Lake

The Princess/ Tide Lake property was acquired from Rocky Mountain Energy Corp., and is now being operated under RMAC, a wholly owned subsidiary of the Trust. RMAC has an average working interest of 50% in 25,000 acres in the Princess area. Production is primarily from the Sunburst and Pekisko formations. Sunburst production consists of gas and 23 degree API crude oil. In December 2004, 8 wells were producing 304 bbl/d net (330 bbl/d gross) of crude oil and 540 mcf/d net (750 mcf/d) gross of natural gas from the Sunburst formation on a working interest basis before royalties. The Pekisko production consists of gas and 27 degree API crude oil. As of December 2004, 17 Pekisko oil wells were producing 343 bbl/d of crude oil and 670 mcf/d of natural gas from the Pekisko formation on a working interest basis before royalties. Two wells have been drilled and completed in the Sunburst formation with seven more planned upon the approval of a pending down-spacing application. Six wells have been drilled and completed in the Pekisko formation, with two more planned.

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Enterra has an average working interest of 50% of 3,040 acres in the Tide Lake area. Production, consisting of 27 degree API oil, is from the Pekisko formation. In December 2004, there were 3 wells producing 51 bbl/day of crude and 50 mcf/d of natural gas from the Pekisko formation on a working interest basis before royalties. Two development wells have been drilled and completed in the Pekisko in 2004 and two more are planned for 2005.

McDaniel has assigned total net proved remaining reserves of 676 mbbl of oil, 1,278 mmcf of natural gas and 22 mbbl of natural gas liquids.

Sylvan Lake

The Sylvan Lake property is located 24 miles west of the town of Red Deer, Alberta. Enterra s assets include an average working interest of 72% in 4,320 gross acres of land as well as 27 producing oil wells and 1 producing gas well. Enterra completed the development of 40-acre spacing wells in the Pekisko G pool, and also drilled four subsequent oil wells on 20 acre spacing. At December 31, 2004, the field was producing 680 bbl/day of 14 degree API oil from 27 wells with 815 mcf/d of associated gas plus an additional 60 mcf/d of non-associated gas on a working interest basis before royalties. Production is flow lined into an Enterra operated central treating facility. Non-associated gas is conserved and flow lined to the Husky Sylvan Lake gas plant. Clean oil is trucked from the facility to sales.

McDaniel and Associates has assigned total proved remaining reserves of 1,055 mbbl of oil, 692 mmcf of solution gas, 25 mmcf of non-associated gas and 61 mbbl of natural gas liquids. Based on the success of the 4-well 2004 drilling program, Enterra may drill three wells with further down spacing in other areas of the pool. The reservoir has net pays up to 40 m (130 ft). Enterra owns a 3-D seismic program that covers the Sylvan Lake Pekisko G pool.

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Reserves Summary

Enterra Energy Trust is required to comply with the National Instrument 51-101, issued by the Canadian Securities Administrators, in all its reserves related disclosures. NI 51-101 came into effect on September 30, 2003 and is applicable for financial years ended on or after December 31, 2003. NI 51-101 brought about significant changes in which reporting issuers manage and publicly disclose information relating to their oil and gas reserves, mandates annual disclosure requirements and prescribes new reserve definitions as follows:

Proved reserves (P90) - this is a conservative estimate of remaining reserves. For reported reserves this means there must be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Proved plus Probable (P50) - this is a reasonable estimate of remaining reserves. For reported reserves there must be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves. The probable reserves will no longer be risked by 50 percent as they are implicitly risked due to the nature of the new definition of reserves.

The purpose of NI 51-101 is to enhance the quality, consistency, timeliness and comparability of oil and gas activities by reporting issuers and elevate reserves reporting to a higher level of accountability.

In the United States, registrants are required to disclose reserves using the standards contained in U.S. Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No.69 Disclosures About Oil and Gas Producing Activities (FAS 69). Such information is contained in Supplemental disclosure about Oil and Gas activities Unless otherwise indicated, all of the reserves and production information disclosure in this Form 20-F is in compliance with Industry Guide 2.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. Enterra concurs with this assessment.

In this Form 20-F, certain natural gas volumes have been converted to barrels of oil equivalent (BOEs) on the basis of six thousand cubic feet (Mcf) to one barrel (bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the wellhead.

Net proved reserve volumes at December 31, 2004 are based on Enterra s interest in its total proved reserves after royalties as defined in FAS 69. Gross proved reserve volumes at December 31, 2004 are based on Enterra s interest in its total proved reserves before royalties.

The Trust has its reserves evaluated by independent engineers every year. McDaniel and Associates Consultants Ltd. (McDaniel) independently evaluated the Enterra s reserves at December 31, 2004. These recovery and reserve estimates in the described properties are estimates only; the actual reserves in the properties in which we have an interest may be more or less than those calculated. The extent and character of the material information supplied by Enterra including, but not limited to, ownership, well data, production, price, revenues, operating costs and contracts were relied upon by McDaniel in preparing the report. In the absence of such information, McDaniel relied upon their opinion of reasonable practice in the industry. Additional information can be found in our Renewal Annual Information Form filed on the internet at www.sedar.com.

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Reserve Quantity Information

Estimated net quantities of proved gas and oil (including condensate) reserves at December 31, 2004, 2003 and 2002, and changes in the reserves during those years, are shown in the following two tables. Reserve volumes are reported on both net and gross of royalties basis.

	2004 Net	2003 Net	2002 Net	**2004 Gross**	2003 Gross	2002 Gross
Proved developed and undeveloped reserves						
Oil (boe)						
At January 1	**4,457**	4,193	3,472	**5,149**	5,234	4,127
Changes in reserves:						
Extensions, discoveries and other additions	**139**	1,962	2,054	**158**	2,267	2,564
Revisions of previous estimates	**(96)**	(214)	(195)	**65**	(458)	(61)
Production	**(1,672)**	(1,062)	(446)	**(2,161)**	(1,406)	(533)
Purchases of oil in place	**2,363**	98		**2,684**	113	
Sales of oil in place	**(21)**	(520)	(692)	**(24)**	(601)	(863)
At December 31	**5,170**	4,457	4,193	**5,871**	5,149	5,234
Proved developed reserves Oil						
At January 1	**4,457**	3,239	3,131	**5,149**	3,952	3,734
At December 31	**5,069**	4,457	3,239	**5,755**	5,149	3,952

	2004 Net	2003 Net	2002 Net	**2004 Gross**	2003 Gross	2002 Gross
Proved developed and undeveloped reserves						
Gas (boe)						
At January 1	**744**	1,706	1,342	**1,018**	2,174	1,794
Changes in reserves:						
Extensions, discoveries and other additions	**25**	462	752	**28**	534	939
Revisions of previous estimates	**(167)**	(167)	(70)	**(124)**	(183)	(176)
Production	**(322)**	(322)	(263)	**(416)**	(427)	(314)
Purchases of gas in place	**637**	23		**723**	26	
Sales of gas in place		(958)	(55)		(1,106)	(69)
At December 31	**917**	744	1,706	**1,229**	1,018	2,174
Proved developed reserves Gas						
At January 1	**744**	1,606	1,233	**1,018**	2,038	1,650

At December 31	**909**	744	1,606	**1,219**	1,018	2,038

Proved developed reserves are defined as reserves that can be expected to be recovered through existing wells with existing facilities and operating methods.

Proved undeveloped reserves are defined as reserves that can be expected to be recovered through the drilling of additional wells and building of additional facilities.

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Production

The following table summarizes the Trust s working interest production, before royalties, during the periods indicated:

	Years ended December 31,						
	2004	**2003**	**2002**	**2001**	**2000**	**1999**	**1998**
Oil and NGL s (mbbls)	2,130	1,409	533	582	410	93	86
Gas (mmcf)	2,495	2,545	1,882	680	63	61	220
Total (MBOE)	2,550	1,834	847	695	421	100	108
Average Production in BOED	6,957	5,024	2,320	1,906	1,150	274	296

Definitions:

BOEPD means barrels of oil equivalent produced per day.

MBOE means thousands of barrels of oil equivalent, meaning one barrel of oil or one barrel of natural gas liquids or ten mcf of natural gas.

MBbls means thousands of barrels, with respect to production of crude oil or natural gas liquids.

MMcf means millions of cubic feet, with respect to production of natural gas.

NGL s means natural gas liquids, being those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Oil and Gas Wells

The following table summarizes the Trust s interest in producing and non-producing oil and gas wells as at December 31, 2004:

	Oil Wells		**Gas Wells**		**Non Producing**		**Grand Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	542	337.0	55	33.2	202	169.5	799	539.7
US	2	0.5					2	0.5
Total	544	337.5	55	33.2	202	169.5	801	540.2

Average Sales Prices

Year ended December 31,	**2004**	**2003**	**2002**
Oil per barrel	$ 43.30	$ 39.12	$ 33.86

Natural Gas per MCF	$ 6.69	$ 6.65	$ 4.08

Average Production Costs

Year ended December 31,	**2004**	**2003**	**2002**
Per BOE	$ 9.23	$ 6.96	$ 7.11

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Land Holdings

At December 31, 2004 the Trust had the following land holdings:

	Canada		United States		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Developed acres	66,265	43,795	520	123	66,785	43,918
Undeveloped acres	69,611	49,054	32,765	12,278	102,376	61,332
Total acres	135,876	92,849	33,285	12,401	169,161	105,250

The number of net acres for which the Trust s rights to explore, develop or exploit will, absent further action, expire within one year are 889 acres in Canada and 9,851 acres in the US for a total of 10,740 acres.

Drilling Activity

The Trust s drilling history is as follows:

	2004	**2003**	**2002**	**2001**	**2000**
Wells drilled	**Gross (Net)**	**Gross (Net)**	**Gross (Net)**	**Gross (Net)**	**Gross (Net)**
Oil	23 (6.4)	31 (31.0)	25 (23.7)	9 (5.0)	9 (8.3)
Natural Gas	3 (0.7)	3 (1.1)	37 (34.0)	8 (3.8)	2 (1.3)
Injection and water disposal	2 (0.3)	6 (6.0)	0 (0.0)	0 (0.0)	0 (0.0)
Abandoned	3 (2.3)	7 (6.4)	0 (0.0)	3 (1.8)	2 (1.1)
Total	31 (9.7)	47 (44.5)	62 (57.7)	20 (10.6)	13 (10.7)

Notes:

(1) Gross wells mean the number of whole wells.

(2) Net wells means Enterra s aggregate working interests in the gross wells.

(3) All wells were development wells, except for 3 (net 3.0) exploration wells drilled in 2003, all of which were abandoned

Present Activities

During the three month period ended March 31, 2005, the Trust drilled the following development wells:

	Q1 2005
Wells drilled	**Gross (Net)**
Oil	8 (1.0)

Natural Gas	4 (0.7)
Injection and water disposal	0 (0.0)
Abandoned	2 (0.4)
Total	14 (1.1)

Delivery Commitments

The Trust has not entered into obligations to provide a fixed and determinable quantity of oil or gas in the near future under existing contracts or agreements. Enterra has never been unable to meet any significant delivery commitments.

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ITEM 5. Operating and Financial Review and Prospects

Overview

The following should be read in conjunction with other financial information included in this annual report on 20-F and with the consolidated financial statements of Enterra Energy Trust (the Trust) contained in the 2004 Annual Report. All amounts are stated in Canadian dollars and in accordance with Canadian Generally Accepted Accounting Principles (GAAP) except where otherwise indicated. Natural gas volumes have been converted to a crude oil equivalent using a ratio of 6 mcf to 1 bbl of oil. Discussion with regard to the Trust s 2005 outlook is based on currently available information.

5.A Operating Results

Comparison of the Year Ended December 31, 2004 to the Year Ended December 31, 2003

Critical Accounting Policies

The Trust follows the full cost method of accounting for oil and natural gas properties and equipment whereby we capitalize all costs relating to its acquisition of, exploration for and development of oil and natural gas reserves. The Trust s consolidated financial condition and results of operations are sensitive to, and may be adversely affected by, a number of subjective or complex judgments relating to methods, assumptions or estimates required under the full cost method of accounting concerning the effect of matters that are inherently uncertain. For example:

(i) Capitalized costs under the full cost method are depleted and depreciated using the unit-of-production method, based on estimated proved oil and gas reserves as determined by independent engineers. To economically evaluate the Trust s proved oil and natural gas reserves, these independent engineers must necessarily make a number of assumptions, estimates and judgments that they believe to be reasonable based upon their expertise and NI 51-101 guidelines. Were the independent engineers to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected. For example, the Trust would have lower net earnings (or net losses) in the event the revised assumptions, estimates and judgments resulted in lower reserve estimates, since our depletion and depreciation rate would then be higher and it might also result in a write-down under the ceiling test. Similarly, the Trust would have higher net earnings in the event the revised assumptions, estimates and judgments resulted in higher reserve estimates.

(ii) The Trust s management also periodically assesses the carrying values of unproved properties to ascertain whether any impairment in value has occurred. This assessment typically includes a review of sales of similar properties to determine a fair market value. These properties would be moved to the cost pool and depleted if this assessment indicates the fair market value is less than the capitalized costs. Were the Trust s management to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected.

Production Revenue

In 2004 production revenue increased by 50% from 2003 to $108.3 million (2003 $72.1 million). During the year we experienced a 10% increase in commodity pricing from the previous year and production increased by 38% to 6,957 boe per day (2003 5,024 boe/day).

The Trust s production in 2004 averaged 6,957 boe/day, consisting of 5,821 bbls/day of oil and 6,817 mcf/day of natural gas, on a mix of 84% oil and 16% natural gas. Enterra s production in 2003 averaged 5,024 boe/day, consisting of 3,862 bbls/day of oil and 6,972 mcf/day of natural gas, on a mix of 77% oil and 23% natural gas.

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SUMMARIZED FINANCIAL AND OPERATIONAL DATA

(in Thousands except for volumes and per unit amounts)	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Exit production rate (boe per day)	7,258	6,460	12%	7,258	6,460	12%
Production revenue	$ 33,593	$ 15,598	115%	$ 108,293	$ 72,097	50%
Average production volumes (boe per day)	7,925	5,206	52%	6,957	5,024	38%
Cash flow from operations [1]	$ 14,103	$ 1,704	727%	$ 50,242	$ 30,693	64%
Cash flow per unit [1]	$ 0.54	$ 0.08	544%	$ 2.15	$ 1.62	33%
Net earnings (loss)	$ 3,417	$ (5,086)	167%	$ 14,764	$ 5,098	190%
Net earnings (loss) per unit	$ 0.13	$ (0.25)	149%	$ 0.63	$ 0.27	135%
Average number of units outstanding	25,974	20,205	37%	23,328	18,954	23%
Average price per bbl of oil	$ 46.90	$ 31.79	48%	$ 43.00	$ 39.12	10%
Average price per mcf of natural gas	$ 6.87	$ 5.91	16%	$ 6.69	$ 6.65	1%
Production expenses per boe	$ 10.98	$ 6.19	77%	$ 9.23	$ 6.96	33%
General and administrative expenses per boe *(cash portion)*	$ 2.61	$ 2.18	20%	$ 1.71	$ 1.69	-1%

(1) *Cash flow from operations is a non-GAAP measure. Cash flow from operations is reconciled to GAAP earnings in the cash flow section below.*

The Trust s production in Q4 of 2004 averaged 7,925 boe/day, consisting of 6,766 bbls/day of oil and 6,954 mcf/day of natural gas, for a mix of 84% oil and 16% natural gas. The Trust s production in Q4 of 2003 averaged 5,206 boe/day, consisting of 4,110 bbls/day of oil and 6,572 mcf/day of natural gas, for a mix of 79% oil and 21% natural gas.

The Trust exited 2004 at a rate of 7,258 boe/day, consisting of 5,905 bbls/day of oil and 8,118 mcf/day of natural gas, for a mix of 81% oil and 19% natural gas. This represents a 12% increase over the 2003 exit rate of 6,460 boe/day.

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3 YEAR SUMMARY

SUMMARIZED FINANCIAL AND OPERATIONAL DATA ***(in Thousands except for volumes and per unit amounts)***		**Year 2004**		**Year 2003**		**Year 2002**
Revenue	$	108,293	$	72,097	$	25,746
Cash flow from operations [1]	$	50,242	$	30,693	$	11,901
Cash flow from operations per unit basic[1]	$	2.15	$	1.62	$	0.65
Cash flow from operations per unit diluted[1]	$	2.13	$	1.62	$	0.63
Net earnings	$	14,764	$	5,098	$	4,881
Net earnings per unit basic	$	0.63	$	0.27	$	0.27
Net earnings per unit diluted	$	0.63	$	0.27	$	0.26
Average number of units outstanding		23,328		18,954		18,309
Total assets	$	200,301	$	116,661	$	104,505
Total bank debt and obligations under capital leases	$	47,316	$	38,129	$	29,358
Distribution per unit	US$	1.42	US$	0.10		N/A

[1] Cash flow from operations is a non-GAAP measure. Cash flow from operations is reconciled to GAAP earnings in the cash flow section below.

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PRODUCTION REVENUE ***(in Thousands except for volumes and pricing)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Crude oil and natural gas liquids	$ 29,196	$ 12,022	143%	$ 91,611	$ 55,185	66%
Natural gas	4,397	3,576	23%	16,682	16,912	-1%
Total production income	$ 33,593	$ 15,598	115%	$ 108,293	$ 72,097	50%
Volumes						
Average oil production (in bbls/day)	6,766	4,110	65%	5,821	3,862	51%
Average gas production (in mcf/day)	6,954	6,572	6%	6,817	6,972	-2%
Average total production (in boe/day)	7,925	5,206	52%	6,957	5,024	38%
Exit oil production (in bbls/day)	5,905	4,890	21%	5,905	4,890	21%
Exit gas production (in mcf/day)	8,118	9,420	-14%	8,118	9,420	-14%
Exit total production (in boe/day)	7,258	6,460	12%	7,258	6,460	12%
Commodity Pricing Benchmarks						
West Texas Intermediate (US$/bbl)	$ 48.28	$ 31.18	55%	$ 41.40	$ 31.10	33%
Exchange rate (US$)	$ 0.80	$ 0.76	5%	$ 0.77	$ 0.72	7%
Edmonton Par ($/bbl)	$ 57.71	$ 39.85	45%	$ 52.55	$ 43.39	21%
NYMEX (US$/mmbtu)	$ 6.87	$ 5.44	26%	$ 6.09	$ 5.49	11%
Alberta Spot ($/mcf)	$ 7.09	$ 5.69	24%	$ 6.79	$ 6.50	4%
Commodity Prices received by Enterra						
Average price received per bbl of oil	$ 49.90	$ 31.78	48%	$ 43.00	$ 39.12	10%
Average price received per mcf of natural gas	$ 6.87	$ 5.91	16%	$ 6.69	$ 6.65	1%

Production Expenses

Production expenses increased by 84% in 2004 and by 170% in Q4 compared to their respective periods in 2003. These increases are a result of higher production rates, the acquisition of higher operating cost properties during the year and overall increased industry operating costs.

PRODUCTION EXPENSES ***(in Thousands except for percentages and per boe amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Production expenses	$ 8,007	$ 2,967	170%	$ 23,492	$ 12,762	84%
As a percentage of production revenue	24%	19%	25%	22%	18%	23%

Production expenses per boe	$ 10.98	$ 6.19	77%	$ 9.23	$ 6.96	33%

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Royalties

Royalties (including Crown, freehold and overriding royalties) increased by 39% in 2004 and by 103% in Q4 compared to their respective periods in 2003. These increases are the result of both the increased production in 2004 and the higher commodity prices in effect during the year. Most royalties are calculated on a sliding scale based on commodity prices. As commodity prices increase, so do the royalty rates.

ROYALTIES ***(in Thousands except for percentages and boe amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Royalties	$ 7,958	$ 3,916	103%	$ 24,527	$ 17,656	39%
As a percentage of production revenue	24%	25%	-6%	23%	24%	-8%
Royalties per boe	$ 10.91	$ 8.18	33%	$ 9.63	$ 9.63	0%

General and Administrative Expenses

General and administrative cash expenses increased by 41% in 2004 and 83% in Q4 compared to their respective periods in 2003. Approximately 80% of the increase in 2003 is the result of additional staffing requirements. Other areas that incurred higher expenses were marketing and travel costs, insurance premiums, and higher regulatory compliance costs both for the Canadian and U.S. exchanges. The non-cash portion of general and administrative expenses relates to the fair market value assigned to warrants and options issued.

GENERAL AND ADMINISTRATIVE EXPENSES ***(in Thousands except for percentages and per boe amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
General and administrative expenses cash portion	$ 1,906	$ 1,042	83%	$ 4,362	$ 3,104	41%
General and administrative expenses non-cash portion	$ (606)			$ 78	$ 281	-72%
As a percentage of production revenue (cash portion)	6%	7%	-15%	4%	4%	-6%
General and administrative expenses per boe (cash portion)	$ 2.61	$ 2.18	+20%	$ 1.71	$ 1.69	1%

Interest Expense

Interest expense increased by 27% in 2004 and increased by 20% in Q4 compared to their respective periods in 2003. The 2004 increase is due to the higher average outstanding loan balances during the year. The increase in Q4 is due to the fact that, on average, the Q4 loan balances were higher in 2004 because of acquisitions and drilling activity in 2004 compared to 2003.

INTEREST EXPENSE ***(in Thousands except for percentages and per boe amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Long-term debt, including bank debt at end of period	$ 47,316	$ 38,128	24%	$ 47,316	$ 38,128	24%
Interest expense	$ 491	$ 410	20%	$ 2,222	$ 1,749	27%
As a percentage of production revenue	2%	3%	44%	2%	2%	-15%
Interest expense per boe	$ 0.67	$ 0.86	-21%	$ 0.87	$ 0.95	-8%

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Depletion and Depreciation

Depletion and depreciation expense increased by 52% in 2004 and by 88% in Q4 compared to their respective periods in 2003. The increase is due to a higher production rate in the year and Q4 2004.

DEPLETION AND DEPRECIATION EXPENSE ***(in Thousands except for percentages and per boe amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Depletion and depreciation expense	$ 11,650	$ 6,210	88%	$ 35,438	$ 23,306	52%
As a percentage of production revenue	35%	40%	-13%	33%	33%	0%
Depletion and depreciation expense per boe	$ 15.98	$ 12.97	23%	$ 13.92	$ 12.71	10%

Income and Capital Taxes

The Trust, pursuant to the Trust Indenture, is not subject to income tax as all of the taxable income of the Trust is distributed to Unitholders in the form of taxable distributions. The fully owned subsidiaries of the Trust are subject to tax if the discretionary deductions available within the provisions of the Canadian Income Tax Act are inadequate to reduce taxable income to zero. These discretionary deductions are often referred to as tax pools.

Total tax expense reflected in the Income Statement is a combination of the Current and Future Income Tax provisions. The current tax expense relates to Large Corporation Tax. Future Income tax expense reflects the temporary differences between the accounting value and the tax value of the pools, valued at the anticipated future tax rate when the temporary differences are anticipated to reverse.

The Trust has neither directly nor indirectly incurred current income tax liabilities since the formation of the Trust in 2003. A $0.8 million tax liability was acquired in conjunction with the purchase of Rocky Mountain Energy Corp. related to periods prior to acquisition. Management regularly reviews the potential for cash income taxes liabilities, and undertakes strategies to minimize this potential for taxes in future years. The Large Corporation Tax will continue in future years as a cash tax on the Trust.

The size of available tax pools is one indicator of the Trust s ability to minimize cash income taxes in the future. Should tax pools become inadequate to reduce taxable income of the subsidiary corporations then cash income taxes will become due indirectly by the Trust. These cash taxes will reduce the funds available for distribution to Unitholders.

TAX POOLS ***(in Thousands except for percentages)***

Estimated tax pools at December 31	**Year 2004**
Canadian oil and gas property expense (COGPE)	$ 22,901
Canadian exploration expense (CEE)	4,688
Canadian development expense (CDE)	36,312
Undepreciated capital cost (UCC)	29,234
Non-capital losses	32,235

Other	1,444
	$ 126,814

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Earnings

In 2003, earnings were reduced by the re-organization costs related to the conversion to a trust in the fourth quarter of 2003.

EARNINGS ***(in Thousands except for per unit amounts)***

	Q4 2004	Q4 2003	*Change*	Year 2004	Year 2003	*Change*
Earnings (loss) before income taxes	**$ 3,247**	**$ (4,710)**	**169%**	**$ 14,953**	**$ 7,220**	**107%**
Deduct income taxes	$ (170)	$ (377)	145%	$ (189)	$ (2,122)	-91%
Net earnings (loss)	**$ 3,417**	**$ (5,087)**	**167%**	**$ 14,764**	**$ 5,098**	**190%**
Net Earnings (loss) as a percentage of revenue	10%	33%	130%	14%	7%	93%
Net Earnings (loss) on a per boe basis	$ 4.69	$ (10.62)	144%	$ 5.30	$ 2.77	109%
Per unit information						
Net earnings (loss) per unit	$ 0.13	$ (0.25)	152%	$ 0.63	$ 0.27	135%
Average number of units outstanding	25,974	20,205	29%	23,328	18,954	23%

Cash Flow From Operations

Cash flow grew by 64% in 2004 and by 728% in Q4 compared to their respective periods in 2003. s a percentage of revenue, cash flow decreased by 8% to 46% in 2004 compared to 2003 and increased by 284% in Q4 2004 to 42% compared to Q4 2003.

Cash flow from operations increased by 38% in 2004 and by 88% in Q4 compared to their respective periods in 2003. As a percentage of revenue, cash flow from operations decreased by 8% to 46% in 2004 compared to 2003 and decreased by 13% in Q4 2004 to 42% compared to Q4 2003. The difference between cash flow and cash flow from operations is the $5.8 million re-organization cost incurred in 2003 to convert Enterra Energy Corp. to a trust.

Higher operating cost properties acquired in 2004 contributed to the decrease in cash flow as a percentage of revenue.

As mentioned earlier, it is management s view that cash flow from operations is a very useful measure of performance, especially in light of Enterra s conversion to an oil and gas income trust. Cash flow from operations is the key factor in setting the monthly distribution rate. As discussed in the earnings section above, cash flow from operations is also a good benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events that may otherwise distort the financial results. Cash flow from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

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CASH FLOW FROM OPERATIONS ***(in Thousands except for per unite amounts)***

	Q4 2004	Q4 2003	Change	Year 2004	Year 2003	Change
Net earnings (loss)	**$ 3,417**	**$ (5,087)**	**167%**	**$ 14,764**	**$ 5,098**	**190%**
Add back depletion and depreciation	11,650	6,210	88%	35,438	23,306	52%
Add back (deduct) amortization of deferred financing charges	(18)	(27)	33%	33	262	- 87%
Add back (deduct) future income taxes	(340)	331	203%	(71)	1,988	- 104%
Deduct amortization of deferred gain					(237)	- 100%
Asset Retirement Expenditures		(5)	-100%		(6)	- 100%
Add back (deduct) non-cash expense related to warrants/ options	(606)	282	315%	78	282	- 72%
Cash flow from operations	**$ 14,103**	**$ 1,704**	**728%**	**$ 50,242**	**$ 30,693**	**64%**
Cash flow from operations as a percentage of revenue	42%	11%	284%	46%	51%	- 8%
Cash flow from operations on a per boe basis	$ 19.34	$ 3.56	444%	$ 19.73	$ 16.74	18%
Per unit information						
Cash flow from operations per unit	$ 0.54	$ 0.08	544%	$ 2.15	$ 1.62	33%
Average number of units outstanding	25,974	20,205	29%	23,328	18,954	23%

Capital Expenditures

Capital expenditures, net of disposals, for the year ended December 31, 2004 were $65.2 million (2003 $33.3 million) including $36.0 million of assets obtained through the acquisition of Rocky Mountain Energy Corp. and $20.0 for the acquisition of Eastern Central Alberta (see notes 4 and 5 to the Financial Statements). Proceeds on disposal of oil and gas properties were $1.1 million in 2004 (2003 $18.3 million). These proceeds were used to reduce debt and replenish working capital. In addition to cash capital expenditures, $11.8 million of net Asset Retirement Obligations (ARO) were charged to Property Plant and Equipment.

CAPITAL EXPENDITURES

(In Thousands except for percentages)	**Year 2004**	**Year 2003**	*Change*
Property acquisitions	$ 30,385	$ 8,539	256%
Proceeds on disposal of properties	(1,177)	(18,263)	- 94%
Drilling (exploration and development)	11,001	28,390	- 61%
Facilities and equipment	24,475	14,368	70%
Other	555	280	98%
Net additions before ARO	$ 65,239	$ 33,314	96%

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Cash Distributions

The Trust paid distributions of US$0.10 per unit for the first two months of 2004. The distribution was raised to US$0.11 per unit for the months of March, April and May, raised to US$0.12 per unit for the months of June, July and August, raised to US$0.13 per unit for the months of September, October and November and raised to US$0.14 per unit for the month of December 2004. Cash distributions are paid on the 15th of the following month (e.g. the March distribution would be paid on April 15).

For Canadian tax purposes 47.84% of the 2004 distributions are taxable income to Unitholders for the 2004 tax year. The remaining 52.16% is a tax-deferred return of capital that will reduce the Unitholders cost base of the unit for purposes of calculating a capital gain or loss upon ultimate disposition of the trust units.

The Trust s distributions are typically qualifying dividend income for U.S. Unitholders, without any portion deemed a return of capital.

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NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In December 2001, The Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, Hedging Relationships (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. Enterra enters into financial instruments to manage its commodity price risk that do not qualify as hedges under the new accounting guideline. We have elected to not apply hedge accounting to any of our financial instruments. Effective January 1, 2004, we recorded the fair value of financial instruments as a liability of $1.0 million on the balance sheet. Future changes in fair value of the financial instruments were recorded as a gain or loss in oil and gas sales in the income statement.

Full Cost Accounting

Effective January 1, 2004, the Trust adopted Accounting Guideline 16, Oil and Gas Accounting Full Cost which replaces AcG-5 Full Cost Accounting in the Oil and Gas industry. AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset.

Asset Retirement Obligations

Effective January 1, 2004, the Trust retroactively adopted CICA handbook Section 3110 Asset Retirement Obligations . The new recommendations require the recognition of the fair value of obligations associated with the retirement of long-lived assets to be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense, which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

Unit-based Compensation

Effective January 1, 2004, the Trust adopted the fair value method of accounting for options on a retroactive basis, without prior period restatement. In the past, the Trust measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same as the grant date, no compensation cost was recognized on any option issuance. In 2003, the Trust disclosed pro forma net earnings and earning per unit as if compensation cost for the Trust s unit-base compensation plan had been determined based on the fair value at the grant date for awards made under the plan subsequent to January 1, 2002. The estimated fair value of the options issued is determined using a Black-Scholes option-pricing model.

Variable Interest Entities (VIEs)

In June 2003, the CICA issued Accounting Guideline 15 Consolidation of Variable Interest Entities (AcG-15). AcG-15 defines VIEs as entities in which either: the equity at risk is not sufficient to permit that entity to finance its activities without additional financial support from other parties; or equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. AcG-15 harmonizes Canadian and U.S. GAAP and provides guidance for companies consolidating VIEs in which it is the primary beneficiary. The guideline is effective for all annual and interim periods beginning on or after November 1, 2004. We have performed a review of entities in which the Trust has an interest and have determined that we do not have any variable interest entities at this time.

Exchangeable Shares

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On January 19, 2005, the CICA issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts that states that, effective June 30, 2005, equity interests held by third parties in subsidiaries of an income trust should be reflected as either non-controlling interest or debt in the consolidated balance sheet unless they meet certain criteria. EIC-151 requires that the shares be nontransferable in order to be classified as equity. The exchangeable shares issued by the Trust are transferable and, in accordance with EIC-151, will be reclassified to non-controlling interest on the consolidated balance sheet. In addition, a portion of consolidated income or loss before non-controlling interest will be reflected as a reduction to such income or loss in the Trust s consolidated statement of income. Prior periods will be retroactively restated.

U.S. Pronouncements

The following standards issued by the FASB do not impact us at this time:

(a) In December 2004, FASB issued statement 123R Share Based Payments that establishes the standards for the accounting for transactions in which an entity exchanges its equity for goods or services. The statement focused primarily on the accounting for transactions in which an entity obtains employee services in exchange for share-based consideration. The statement establishes a standard to account for such transactions using a fair-value-based method. The effective date for implementation of this standard would be the first interim or annual period beginning on or after December 15, 2005 for transactions entered into on or after the effective date. Management has not yet assessed the impact of this standard on our results of operations or financial position.

(b) In December 2004, SFAS issued statement No. 153 Exchanges of Non-monetary Assets an amendment of APB Opinion No. 29. The statement eliminates the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary exchanges that do not have commercial substance. A non-monetary exchange is defined as having commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. This statement is effective for non-monetary transactions in fiscal periods that begin after Juen 15, 2005. Management does not expect the adoption of this statement to have any material impact on our results of operations or financial position.

The Trust will continue to assess the applicability of these standards in the future.

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Comparison of the Year Ended December 31, 2003 to the Year Ended December 31, 2002

Overview

Enterra managed to achieve record revenue, cash flow and earnings in 2003 while converting itself to an oil and gas income trust during the fourth quarter. Cash flow from operations, excluding the one-time re-organization costs of $5.8 million, was in excess of $36 million for the year or $1.92 on a per unit basis. As a trust, we established an initial monthly distribution level at US$0.10 per unit. The first distribution was paid on January 15, 2004 for the month of December 2003. Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate.

Summarized financial and operational data ***(in Thousand s except for volumes and per unit amounts)*** }

	2003	**2002**	*Change*
Exit production rate (boe per day)	6,460	5,335	+ 21%
Average production revenue	$ 72,097	$ 25,746	+ 180%
Average production volumes (boe per day)	5,024	2,320	+ 117%
Cash flow from operations [(1)]	$ 30,693	$ 11,901	+ 158%
Cash flow from operations per unit [(1)]	$ 1.61	$ 0.65	+ 148%
Average number of units outstanding *(after giving effect to trust conversion)*	18,954	18,309	+ 4%
Average price per bbl of oil	$ 39.12	$ 33.86	+ 16%
Average price per mcf of natural gas	$ 6.65	$ 4.08	+ 63%
Operating costs per boe	$ 6.96	$ 7.11	- 2%
General and administrative expenses per boe *(cash portion)*	$ 1.69	$ 1.99	- 15%

[(1)]*Cash flow from operations is a non-GAAP measure. Cash flow from operations is reconciled to GAAP earnings in the cash flow section below.*

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2 YEAR SUMMARY

Summarized financial and operational data ***(in Thousand s except for per unit amounts)*** }

	2003	2002
Revenue	$ 72,097	$ 25,746
Net earnings	$ 5,098	$ 4,881
Net earnings per unit basic	$ 0.27	$ 0.27
Net earnings per unit diluted	$ 0.27	$ 0.26
Average number of units outstanding *(after giving effect to trust conversion)*	18,954	18,309
Total assets	$ 116,661	$ 104,505
Total long-term debt *(including bank debt and capital leases)*	$ 38,129	$ 29,358
Distribution per unit [(1)]	US$ 0.10	N/A

[(1)] *Only one distribution for the month of December 2003, paid on January 15, 2004 for US$0.10 per unit.*

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PRODUCTION REVENUE

Production revenue has increased by 180% in 2003 or to $72.1 million ($25.7 million in 2002). Approximately 30% of this increase was as a result of higher commodity prices during 2003 and 70% was due to the higher production volumes in 2003.

Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra s production in 2003 averaged 5,024 boe/day, consisting of 3,862 bbls/day of oil and 6,972 mcf/day of natural gas, for a mix of 77% oil and 23% natural gas.

Enterra exited 2003 at a rate of 6,460 boe/day, consisting of 4,890 bbls/day of oil and 9,420 mcf/day of natural gas, for a mix of 76% oil and 24% natural gas. This represents a 21% increase over the 2002 exit rate of 5,335 boe/day.

Production revenue ***(in Thousand s except for volumes and pricing)***

	2003	**2002**	*Change*
Crude oil and natural gas liquids	$ 55,185	$ 18,075	+ 205%
Natural gas	16,912	7,671	+ 120%
Total production income	$ 72,097	$ 25,746	+ 180%
Volumes			
Average oil production (in bbls/day)	3,862	1,460	+ 164%
Average gas production (in mcf/day)	6,972	5,157	+ 35%
Average total production (in boe/day)	5,024	2,320	+ 117%
Exit oil production (in bbls/day)	4,890	4,205	+ 16%
Exit gas production (in mcf/day)	9,420	6,780	+ 39%
Exit total production (in boe/day)	6,460	5,335	+ 21%
Commodity Pricing Benchmarks			
West Texas Intermediate (US$/bbl)	31.10	26.13	+ 19%
Exchange rate (US$)	0.72	0.64	+ 12%
Edmonton Par ($/bbl)	43.39	40.20	+ 8%
NYMEX (US$/mmbtu)	5.49	3.36	+ 63%
Alberta Spot ($/mcf)	6.50	3.96	+ 64%
Commodity Prices received by Enterra			
Average price received per bbl of oil	39.12	33.86	+ 16%
Average price received per mcf of natural gas	6.65	4.08	+ 63%

PRODUCTION EXPENSES

Production expenses increased by 112% in 2003 compared to 2002. This increase is consistent with the higher production levels in 2003. Both as a percentage of revenue and on a per boe basis, Enterra reduced its operating costs in 2003, mainly due to operating efficiencies gained at Clair in the fourth quarter of 2003 by implementing a sales line which eliminated trucking and terminal fees for that area.

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	2003	**2002**	*Change*
Production expenses	$ 12,762	$ 6,018	+ 112%
As a percentage of production revenue	18%	23%	- 22%
Production expenses per boe	$ 6.96	$ 7.11	- 2%

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ROYALTIES

Royalties (which include Crown, freehold and overriding royalties) increased by 320% in 2003 compared to 2002. This increase is the result of both the increased production in 2003 and the higher commodity prices in effect during the year. Most royalties are calculated on a sliding scale based on commodity prices. As commodity prices increase, so do the royalty rates. Conversely, the Alberta Royalty Tax Credit is reduced as commodity prices increase. Since royalties are not calculated by reference to any hedging position entered into by Enterra, any hedging loss will result in a higher royalty expense as a percentage of production revenue. These factors were the reason for the increase (50% for the year) in royalty expense both as a percentage of production revenue and on a per boe basis.

Royalties ***(in Thousand s except for percentages and per boe amounts)***

	2003	**2002**	Change
Royalties	$ 17,656	$ 4,203	+ 320%
As a percentage of production revenue	24%	16%	+ 50%
Royalties per boe	$ 9.63	$ 4.96	+ 94%

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased by 84% in 2003 compared to 2002. Approximately 80% of the increase in 2003 is the result of additional staffing requirements. Other areas that incurred higher expenses were marketing and travel costs, insurance premiums, and higher regulatory compliance costs both for the Canadian and U.S. exchanges. Capitalized general and administrative costs were consistent in both years, $1,787,000 (or 32% of total general and administrative expenses) in 2003 and $1,450,900 (or 39% of total general and administrative expenses) in 2002. The non-cash portion of general and administrative expenses in 2003 relate to the value assigned to 200,000 warrants (see Note 9(h) of the Financial Statements for details).

General and administrative expenses ***(in Thousand s except for percentages and per boe amounts)***

	2003	**2002**	*Change*
General and administrative expenses cash portion	$ 3,104	$ 1,683	+ 84%
General and administrative expenses non-cash portion	$ 281		
As a percentage of production revenue (cash portion)	4%	7%	- 43%
General and administrative expenses per boe (cash portion)	$ 1.69	$ 1.99	- 15%

INTEREST EXPENSE

Interest expense increased by 42% in 2003 compared to 2002. The 2003 increase is due to the higher average outstanding loan balances during the year.

Interest expense ***(in Thousand s except for percentages and per boe amounts)***

	2003	**2002**	*Change*
Long-term debt, including bank debt at end of period	$ 38,128	$ 29,358	+ 30%
Interest expense	$ 1,749	$ 1,236	+ 42%
As a percentage of production revenue	2%	5%	- 60%

Interest expense per boe	$ 0.95	$ 1.46	- 35%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 152% in 2003 compared to 2002. The increase is due to a higher production rate in 2003. The depletion base was consistent in both years as the capital expenditures, net of proceeds on disposal of properties, were $33 million in 2003 and $ 30 million in 2002.

Depletion and depreciation ***(in Thousand s except for percentages and per boe amounts)***

	2003	2002	Change
Depletion and depreciation expense	$ 23,306	$ 9,449	+ 146%
As a percentage of production revenue	32%	36%	- 11%
Depletion and depreciation expense per boe	$ 12.71	$ 10.99	+ 16%

INCOME AND CAPITAL TAXES

The combined federal and provincial income taxes decreased in 2003 to 40.75% from 42.12% in 2002. The actual tax provision recorded on the financial statements is at much lower rates in both 2003 and 2002 (29.25% in 2003 and 16.96% in 2002). The rate was very low in 2002 mainly because of the $3.1 million gain on redemption of preferred shares that was not a taxable gain for tax purposes, resulting in a lower tax provision in that year. The rate was also lower in 2003 mainly due to changes in the timing differences related to the Crown royalties and the resource allowance calculation, and to differences related to the Trust distributions, which are deductible in part for tax purposes but are not deducted to arrive at net earnings.

Income and capital taxes (*in Thousand s except for percentages)*

	2003	2002	Change
Income tax expense	$ 2,122	$ 997	+ 113%
Combined federal and provincial income tax rate	40.75%	42.12%	- 3%
Actual tax rate as a percentage of net earnings	29.25%	16.96%	+ 72%
Estimated tax pools at December 31			
Canadian oil and gas property expense (COGPE)	$ 13,911	$ 20,148	
Canadian exploration expense (CEE)	$ 8,832	$ 9,870	
Canadian development expense (CDE)	$ 43,463	$ 4,708	
Undepreciated capital cost (UCC)	$ 31,308	$ 27,109	
Other	$ 2,906	$ 2,331	
Total	$ 100,420	$ 64,166	+ 56%

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EARNINGS

Earnings were higher in 2002 because of the impact of a $3.1 million gain on redemption of preferred shares. The opposite occurred in 2003 as earnings were reduced by the re-organization costs related to the conversion to a trust structure in the fourth quarter of 2003.

Earnings ***(in Thousand s except for per unit amounts)***

	2003	**2002**	*Change*
Earnings (loss) before income taxes	$ 7,220	$ 5,878	+ 23%
Deduct income taxes	(2,122)	(997)	
Net earnings (loss)	**$ 5,098**	$ 4,881	+ 4%
Per unit information			
Net earnings (loss) per unit	$ 0.27	$ 0.27	0%
Average number of units outstanding	18,954	18,309	+ 4%

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CASH FLOW FROM OPERATIONS

Cash flow from operations grew by 205% in 2003 compared to 2002. As a percentage of revenue, cash flow from operations was consistent in both years, at 51% of revenue in 2003 compared to 46% in 2002.

Higher production volumes and higher commodity prices in 2003 are the main factors behind the increase.

The changes on a per unit basis showed similar results: an increase of 195% in 2003 compared to 2002.

As mentioned earlier, it is management s view that cash flow from operations is a very useful measure of performance, especially in light of Enterra s conversion to an oil and gas income trust. Cash flow from operations is the key factor in setting the monthly distribution rate. As discussed in the earnings section above, cash flow from operations is also a good benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events that may otherwise distort the financial results. Cash flow from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Cash flow from operations ***(in Thousand s except for per unit amounts)***

	2003	2002	*Change*
Net earnings (loss)	**$ 5,098**	**$ 4,881**	**+ 4%**
Add back depletion and depreciation	23,306	9,449	
Add back (deduct) amortization of deferred financing charges	262	391	
Add back future income taxes	1,988	865	
Add back non-cash expense related to value of warrants	282		
Deduct asset retirement expenditures	(5)	(49)	
Deduct amortization of deferred gain	(238)	(524)	
Deduct gain on redemption of preferred shares		(3,111)	
Cash flow from operations [(1)]	**$ 30,693**	**$ 11,901**	**+ 158%**
Cash flow from operations as a percentage of revenue [(1)]	42%	46%	- 10%
Cash flow from operations on a per boe basis [(1)]	$ 19.73	$ 14.11	+ 40%
Per unit information			
Cash flow from operations per unit	$ 1.61	$ 0.65	+ 148%
Average number of units/shares outstanding	18,954	18,309	+ 4%

[(1)] Cash flow from operations is a non-GAAP measure. Cash flow from operations is reconciled to GAAP earnings in the cash flow section below.

CAPITAL EXPENDITURES

Capital expenditures, net of disposals, for the year ended December 31, 2003 were $33.3 million (2002 $30.1 million). Enterra drilled 47 wells in 2003, resulting in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra drilled 62 wells (57.7 net) in 2002, resulting in 25 oil wells (23.7 net) and 37 gas wells (34.0 net). Proceeds on disposal of oil and gas properties were $18.3 million in 2003 (2002 $5.8 million). These proceeds were used to reduce debt and replenish working capital and relate almost exclusively to the sale of the Grand Forks properties, which occurred in the second quarter of 2002 and which accounted for $5.3 million of the total proceeds.

Capital expenditures ***(in Thousand s except for percentages)***

	2003	**2002**	*Change*
Property acquisitions	$ 8,539	$ 4,829	
Proceeds on disposal of properties	(18,263)	(5,810)	
Drilling (exploration and development)	28,390	21,519	
Facilities and equipment	14,368	9,347	
Other	280	235	
Total	$ 33,314	$ 30,120	+ 11%

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CASH DISTRIBUTIONS

The Trust paid distributions of US$0.10 per unit for the month of December 2003 and for the first two months of 2004. The distribution for the month of March 2004 was raised to US$0.11 per unit. Cash distributions are paid on the 15th of the following month (e.g. the March distribution would be paid on April 15).

The Trust s distributions are highly dependent on commodity prices, primarily the price of crude oil. The Trust mitigates this risk by hedging some of its oil production. A detailed schedule of our hedging history and current position is included in the next section dealing with liquidity and capital resources.

For Canadian tax purposes 72.37% of the December distribution is taxable income to Unitholders for the 2003 tax year. The remaining 27.63% is a tax deferred return of capital that will reduce the unitholder s cost base of the unit for purposes of calculating a capital gain or loss upon ultimate disposition of the trust units.

For U.S. tax purposes, the December distribution is a 2004 taxable event. The Trust s distributions are typically dividend income for U.S. Unitholders, without any portion deemed a return of capital.

5 B. Liquidity and Capital Resources

Enterra s bank debt at December 31, 2004 was $43.9 million (2003 $34.0 million). In both periods the funds were used to acquire capital assets and support ongoing operations. At December 31, 2004 The Trust s bank facility consisted of a line of credit of $45.0 million (2003 $34.7 million). The line of credit was reduced by $1 million per month until April 30, 2005 when the line was set at $41 million. Interest on amounts drawn is based on the bank s prime rate plus 1.6% to 2.0%.

In 2002 the Trust closed a sale-leaseback arrangement on some of its production and processing equipment for $5 million. The funds were used for the Trust s 2002 drilling program. The lease agreement calls for 60 monthly payments of $88,802, with an option to purchase of $1 million on the last day of the 60th month. This arrangement is accounted for as a capital lease. At December 31, 2004 the balance outstanding on this capital lease was $3.4 million (2003 $4.2 million).

On January 30, 2004 the Trust closed an acquisition of properties in East Central Alberta for $19.6 million. The effective date of the sale was October 1, 2003.

On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs). These funds were used for drilling projects that Enterra began prior to its conversion to a Trust.

On June 30, 2004 the Trust completed a private placement of 1,650,000 Trust Units at a price of US$10.00 per unit for proceeds of US$16,500,000. These funds were used for property acquisitions.

The Trust has approximately $127 million in tax pools available at December 31, 2004 (2003 $100 million).

The Trust had several costless collars and forward contracts in place during the year in order to reduce the volatility in crude oil pricing. Below is a summary of the financial instruments in place in 2004.

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HEDGING SUMMARY

Description	Quantity	Pricing
Contracts Settled in 2004		
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$ 26.75 per barrel
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$ 26.68 per barrel
Oil contracts from January 1/2003 to June 30/2004	1,000 bbls of oil/day	C$38.50 per barrel
Oil contracts from July 1/2004 to December 31/2004	500 bbls of oil/day	C$40.50 per barrel

The Trust reflected a $3.2 million loss on these contracts in 2004. These financial derivative losses occurred, as the posted commodity price at the time of contract settlement was higher than the contracted pricing as a result of the escalating oil and gas commodity pricing throughout the year. These losses were offset by higher revenue on production.

There were no contracts entered into subsequent to December 31, 2004.

The Trust has sufficient working capital for its present requirements. The working capital deficiency is caused by the requirement of GAAP that $43.9 million bank indebtedness is classified as a current liability even though there is no expectation that the revolving lines of credit will be called by the bank. Our cash flow from operations for 2004 was $50.2 million, so the bank indebtedness represents less than 1 year s cash flow. Our long term business strategy is to grow its oil and gas reserves and distributions by acquiring properties that provide additional oil and gas production and potential for development upside. We are focused on per unit growth. We will finance acquisitions with debt and equity, the optimal mix being one that minimizes Unitholders dilution while maintaining a strong balance sheet.

At December 31, 2004 the Trust was not in compliance with certain non-financial covenants of its credit facility. The Trust s lenders have not declared the Trust to be in default, and the Trust is working to bring itself back into full compliance.

The amounts available under our existing credit facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. Our current credit facility consists of a revolving operating demand loan, and a demand subordinated debt facility. Repayment of all outstanding amounts may be demanded at any time. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to Unitholders may be materially reduced. The credit facilities are in Canadian dollars.

On April 22, 2005, the Trust entered into a committed equity financing facility with Kingsbridge Capital Limited, pursuant to which Kingsbridge committed, subject to certain significant limitations and conditions precedent, to purchase up to US$100 million of Trust Units.

The Trust signed an arrangement agreement dated May 31, 2005 with High Point Resources Inc. (High Point) to acquire all of the issued and outstanding common shares of High Point to be completed by plan of arrangement (the High Point Plan). High Point shareholders will receive 0.105 of a Trust Unit or Exchangeable Share for each High Point common share held. The value of this transaction is approximately US$250 million and the Trust will issue approximately 8.9 million Trust Units in association with the High Point Plan, which equals approximately 35% of the current issued and outstanding Trust Units. This transaction remains subject to approval by the High Point shareholders at a special meeting which is expected to occur in August 2005.

We do not have material commitments for capital expenditures. Our business strategy is to have other companies spend the capital to develop our properties in exchange for us receiving a 30% working interest in the developed properties at no additional cost to us. We also retain the right to purchase the remaining 70% working interest on favorable terms. Any such purchases will be financed by the Trust issuing new trust units and or debt.

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The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

5.C Research and development, patents and licenses, etc.

The Trust has no material research and development programs, patents and licenses etc.

5.D Trend information

Our financial results have been principally affected by increased derived crude oil prices and a gradual strengthening in the Canadian to US dollar.

In recent months, the derived crude oil price has risen from the year-end level of 32.52 US dollar/bbl to 42.45 US dollar/bbl on 20 August 2004, falling to 37.52 US dollar/bbl on 31 August 2004, before approaching 50.00 US dollar/bbl during most of the month of September 2004. Given the current uncertain political environment, the oil price has been volatile and this volatility is expected to continue in the foreseeable future. A high oil price generally results in increased profitability for Enterra.

Oil is priced in US dollars, and the US dollar has been falling against the Canadian dollar for the last few years. This has the effect of reducing the Canadian dollar revenue that would otherwise be received for each barrel of oil sold in US dollars.

5.E Off balance sheet arrangements

There were no off balance sheet arrangements in 2004 or 2003.

5.F Tabular disclosure of contractual obligations

The Trust has two ongoing commitments over the next five years, one related to the capital lease and the other related to the rental payments for our office space. The rental expense was $81,339 in 2004 (2003 $299,132). These commitments are outlined below:

	2005	2006	2007	2008	2009	2010
Minimum capital lease payments	$ 1,065,620	$ 1,065,620	$ 1,799,215	$	$	$
Rental payments office space	795,963	740,610	640,332	661,259	662,130	27,572
	$ 1,861,583	$ 1,806,230	$ 2,439,547	$ 661,259	$ 662,130	$ 27,572

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ITEM 6. Directors, Senior Management and Employees

A. Directors and senior management

Enterra s officers, directors and executive officers as of June 15, 2005 were:

Name	Age	Position
Reginald J. Greenslade	41	Chairman
E. Keith Conrad	66	Director, President, Chief Executive Officer
H.S. (Scobey) Hartley	72	Director
Norman W. Wallace	66	Director
William E. Sliney	66	Director
John Kalman	46	Chief Financial Officer

Reginald (Reg) J. Greenslade. Mr. Greenslade was President, CEO and Director of Old Enterra from the fall of 2001 until November 2003 and continued as Chairman of Enterra Energy Trust after the arrangement. Following the resignation of the CEO and president on January 15, 2005, Mr. Greenslade was appointed President and CEO in addition to his duties as Chairman of the Board until the appointment of Mr. Conrad as President and CEO on June 1, 2005. He is also the Chairman, Chief Executive Officer and director of JED Oil Inc., a publicly traded oil and gas company listed on the American Stock Exchange. He was a director of PASW Inc., a software development company, from February 2001 to July 2001. From 1995 until the formation of Enterra, Mr. Greenslade was the President, CEO and Director of Big Horn Resources Ltd. Prior to his position with Big Horn, Mr. Greenslade was with CS Resources Limited in the areas of exploitation engineering and project management from 1993 to 1995. Prior to 1993, Mr. Greenslade was employed by Saskatchewan Oil and Gas Corporation in the capacities of project management, production, and reservoir engineering. He has extensive experience with secondary recovery schemes and is recognized for his work in the specialized field of horizontal well technology. All the above companies were publicly traded in either the U.S., Canada, or both, during the periods indicated.

E. Keith Conrad. Mr. Conrad is a lawyer with over 40 years of business experience, the last 20 years directly involved with executive management in the oil and gas industry. Mr. Conrad has been Chairman of Macon Resources Ltd., a private company involved in the management of and investment in private and public companies in the oil and gas industry, since 1997. Mr. Conrad holds Bachelors of Arts and Law Degrees from the University of Alberta.

H.S. (Scobey) Hartley. Mr. Hartley has a Bachelor of Science degree in Geology from Texas Tech University. Mr. Hartley has been a director of Enterra since May 2000. Mr. Hartley was the President of Prism Petroleum Ltd. and a predecessor company from December 1990 through December 1996. Mr. Hartley has been the Chairman of Prism Petroleum Ltd. since January 1997. Mr. Hartley has served as the President of Faster Oilfield Services since June 1995, and was the President of Cayenne Energy Corp. from 1990 to 1996. Mr. Hartley was the President and a Director of Scaffold Connection Corporation from February 2000 to November, 2001. Mr. Hartley has been a Director of Cathedral Energy Services Ltd. since June 2001.

Norman W. Wallace. Mr. Wallace has been a director of Enterra since May 2000. Mr. Wallace resigned as a director of Enterra in August 2001 and was reappointed in June 2002. He has been the owner of Wallace Construction Specialties Ltd. since 1972. Mr. Wallace received a Bachelor of Commerce degree from the University of Saskatchewan in 1968.

William E. Sliney. Mr. Sliney became a director on March 19, 2004. He has been the president of PASW, Inc. since August 2001 and was chairman from October 2000 to August 2001. Previously Mr. Sliney was the chief financial officer for Legacy Software Inc. from 1995 to 1998. From 1993 to 1994, Mr. Sliney was chief executive officer for Gumps. Mr. Sliney received his masters in business administration from the University of California at Los Angeles.

John Kalman. Mr. Kalman is a Chartered Accountant with over 23 years of business experience, the last 17 years involved in senior financial positions within the oil and gas industry. Mr. Kalman has been the Vice President, Finance & CFO of Macon Resources Ltd. since November 2004. From January 2004 to October 2004 Mr. Kalman was an independent consultant providing various accounting services to the oil and gas industry. Prior thereto, from October 1999 to December 2003 he was Vice President, Finance and CFO of Gauntlet Energy Corporation a junior oil and gas exploration and development company. Prior thereto, he was Vice President, Finance and CFO of First Calgary Petroleums Ltd. a junior international oil and gas exploration company. Mr. Kalman holds a Bachelor of Commerce Degree from the University of Calgary.

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B. Compensation

The following table provides a summary of compensation earned during the last fiscal year ended December 31, 2004 by our directors and executive officers during 2004. All monetary amounts are in Canadian dollars.

		Annual Compensation			Long-Term Compensation Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Securities Under Options/ SARs Granted (#)	Restricted Shares or Restricted Share Units ($)	LTIP Payouts ($)	All Other Compensation ($)
Reg J. Greenslade (1)	2004				200,000			
Chairman, President, and CEO	2003	200,000						274,000
	2002	157,500	50,000					
Luc Chartrand (2)	2004	200,000	195,458		200,000			
President and Chief Executive	2003	178,060						274,000
Officer	2002	158,355	50,000					
Lynn Wiebe (3)	2004	120,000	127,048		120,000			10,450
Chief Financial Officer	2003	16,950			5,000			6,000
	2002							

(1) *Mr. Greenslade resigned from the offices of President and Chief Executive Officer on completion of Enterra s plan of arrangement with the Trust on November 25, 2003. He was reappointed President, and Chief Executive Officer on January 15, 2005 and resigned from these offices on June 1, 2005.*

(2) *Mr. Chartrand was Chief Financial Officer in 2001, 2002 and for most of 2003. He became President and Chief Executive Officer of Enterra on November 25, 2003 and resigned from these positions and as a director on January 15, 2005.*

(3) *Ms. Wiebe became Chief Financial Officer of Enterra on November 25, 2003. Prior thereto, Ms. Wiebe served Enterra on a consulting basis. She resigned on January 24, 2005.*

Bonus Plan

On January 14, 2004, the directors of Enterra approved an Annual Bonus Plan, which provides for a bonus pool equal to seven/tenths of a percent (0.7%) of the increase in capitalization of the Trust Units each year. There are a number of ways to calculate a bonus pool and each has advantages and disadvantages. The directors of Enterra elected to use a small percentage of the increase in capitalization of the Trust Units because they believe that the best measure of the success of the employees is the increase in value for the Unitholders. Directors, officers and employees of the Trust on December 31st of each year are eligible for a bonus. Allocations of the bonus pool to eligible persons is also at the sole discretion of Enterra s Compensation Committee, although compensation received during the year is the starting point for the allocations. The Annual Bonus Plan requires that it receive the approval of disinterested Unitholders.

Management Contracts

Effective June 1, 2005, we entered into a Management Agreement with Macon Resources Ltd. (Macon) for Macon to provide the services of E. Keith Conrad as President and CEO, and John Kalman as CFO, to Enterra and provide other Management services. Enterra pays Macon fees of $600,000 per year and Macon has also been granted 400,000 options. The agreement has a term of 3 years, which can be amended by mutual consent, and can be terminated with six months notice by either party.

Trust Units Options

We grant trust unit options from time to time to directors, officers, key employees, and consultants. The terms and conditions of the options, in accordance with resolutions of our board of directors and the policies of the Toronto Stock Exchange, will not exceed a term of five years. The option price may be at a discount to market price, which discount will not, in any event, exceed that permitted by any stock exchange on which our shares are listed for

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trading.

Ten percent of our of issued and outstanding trust units from time to time are reserved for issuance pursuant to trust unit options. The aggregate number of trust units reserved for issuance under option grants, together with any other employee trust unit option plans, options for services and employee trust unit purchase plans, will not exceed ten percent of our issued and outstanding trust units. In addition, the aggregate number of trust units so reserved for issuance to any one person shall not exceed five percent of the issued and outstanding trust units.

If an optionee ceases to be eligible due to the loss of corporate office or employment for any reason other than death, the option terminates not later than 30 days after the loss of such corporate office; provided that in the event of termination of employment for cause, the board of directors may resolve that the option shall terminate on the date of such termination. Option agreements also provide that estates of deceased participants can exercise their options for a period not exceeding one year following death.

Trust Unit Options Granted During the Most Recently Completed Financial Year

There were 950,000 trust unit options granted at a weighted average price of C$14.22 during the fiscal year ended December 31, 2004.

Option Grants During Fiscal Year Ended December 31, 2004

	Individual Grants					
		Percentage of Total Options Granted to Employees in			Potential Realizable Value at Assumed Annual Rate of Stock Price	
	Number of Shares of Common Stock	Year Ending Dec. 31, 2004	Exercise Price Per Share	Expiration Date	Appreciation for Option Term (1) 5%	10%
Reg J. Greenslade	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656
Luc Chartrand	200,000	21.05%	$14.00	Jan 14, 2009	$773,588	$1,709,428
Lynn Wiebe	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656
Norman W.G. Wallace	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656
Herman S. Hartley	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656
William E. Sliney	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656
William Turko	120,000	12.63%	$14.00	Jan 14, 2009	$464,153	$1,025,656

(1) Assumed annual appreciation rates are established by regulations and are not a forecast of future appreciation. The amounts shown are pre-tax and assume the options will be held throughout the entire five-year term. If trust units do not increase in value after the grant date of the options, the options are valueless.

Aggregated Option Exercises During the Most Recently Completed Financial Year and Financial Year End Option Values

The following table sets forth the aggregate of options exercised by our executive officers during the year ended December 31, 2004 and the December 31, 2004 year-end values for options granted to the executive officers. All monetary amounts are in Canadian dollars.

	Securities Exercised (#)	Aggregate Value Realized ($)	Unexercised Options at FY-End Exercisable/ Unexercisable (#)	Value of Unexercised in-the-Money Options at FY-End Exercisable/ Unexercisable ($) (1)
Reg J. Greenslade			0/120,000	0/2,677,200
Luc Chartrand			0/200,000	0/4,462,000
Lynn Wiebe			0/120,000	0/2,677,200

(1) The closing price of our trust units on the Toronto Stock Exchange on the last trading day in December 2004 was $18.91.

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C. Board Practices

Board of Directors

The Trust does not have a Board of Directors or officers. The Board of Directors and officers of Enterra act as the Trust s directors and officers. Enterra is authorized to have a board of at least three directors and no more than ten. Enterra currently has five directors. Directors are elected for a term of about one year, from annual meeting to annual meeting, or until an earlier resignation, death or removal. Each officer serves at the discretion of the board or until an earlier resignation or death. There are no family relationships among any of Enterra s directors or officers. Alberta securities laws requires that Enterra have at least two independent outside directors who are not officers or employees of Enterra. Currently, two directors are members of management and three directors are independent.

Currently, the independent directors of Enterra receive an annual retainer of US$5,000 for the Chairman of the Audit Committee and C$5,000 for the other two. Directors are also compensated for their out-of-pocket costs, including travel and accommodation, relating to their attendance at any directors meeting. Finally, the directors of Enterra are entitled to participate in our trust unit option plan and annual bonus plan. During the year ended December 31, 2004, there were 360,000 options granted to the independent directors (not including options granted to a director who is also a named executive officer), and the independent directors received an aggregate of $136,820 under the annual bonus plan. Except as described herein, no compensation by way of annual retainer or meeting fees was paid to directors for acting in such capacity in the year ended December 31, 2004.

Committees of the Board of Directors

Enterra s Board of Directors currently has an audit committee, a compensation committee, a corporate governance committee and a reserves committee.

Audit Committee. Enterra s audit committee consists of Mr. Sliney (Chairman), Mr. Hartley and Mr. Wallace, all three being independent directors. The audit committee reviews in detail and recommends approval of the full board of our annual and quarterly financial statements; recommends approval of the remuneration of our auditors to the full board; reviews the scope of the audit procedures and the final audit report with the auditors, and reviews our overall accounting practices and procedures and internal controls with the auditors.

Compensation Committee. Enterra s compensation committee consists of Mr. Hartley (Chairman), Mr. Wallace and Mr. Greenslade. The compensation committee recommends approval to the full board of the compensation of the Chief Executive Officer, the annual compensation budget for all other employees, bonuses, grants of stock options and any changes to our benefit plans.

Corporate Governance Committee. Enterra s corporate governance committee consists of Mr. Wallace (Chairman), Mr. Greenslade and Mr. Hartley. The corporate governance committee determines the scope and frequency of periodic reports to the board concerning issues relating to overall financial reporting, disclosure and other communications with all stakeholders.

Reserves Committee. Enterra s reserves committee consists of Mr. Wallace (Chairman) and Mr. Hartley. The reserves committee reviews and recommends approval to the full board of Enterra s annual reserve report as prepared by independent reservoir engineers.

D. Employees

At December 31, 2004, we had 3 employees working in the Calgary head office.

Under the Technical Services Agreements with JED Oil Inc. (JED), effective January 1, 2004, JED provides staff while Enterra provides offices and other administrative services to JED. As consultants to Enterra, JED s employees will be eligible to participate in benefit plans of Enterra, if any. At December 31, 2004, JED had approximately 73 employees and consultants working both in the Calgary head office and in field operations. The number of employees has grown each year as the company has grown.

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E. Share ownership

The following table sets forth information regarding beneficial ownership of our trust units as of June 30, 2005, by:

· each of our executive officers and directors; and

· all executive officers and directors as a group.

Trust units not outstanding but deemed beneficially owned because an individual has the right to acquire the trust units within 60 days are treated as outstanding when determining the amount and percentage of trust units owned by that individual and by all directors and executive officers as a group.

	Number of Trust Units/ Exchangeable Shares Beneficially Owned	Percentage of Trust Units/ Exchangeable Shares Outstanding
Reginald J. Greenslade	105,753/24,973	0.4%/6.1%%
H.S. (Scobey) Hartley	74,400	0.28%
Norman W. Wallace	25,000	0.1%
William E. Sliney (1)	127,500	0.49%
All directors and executive officers as a group (five persons)	332,653/24,973	1.27%/6.1%

Notes:

(1) Mr. Sliney did not become a director of Enterra until March 19, 2004.

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ITEM 7. Major Shareholders and Related Party Transactions

A. Major Shareholders

To the extent that it known to Enterra or can be ascertained from public filings, no shareholder has more beneficial ownership of 5% or more of Enterra s Trust Units. To the best of our knowledge, Enterra is not directly or indirectly controlled by another corporation or the government of Canada or any other government. Our management believes that no single person or entity holds a controlling interest in our share capital.

B. Related Party Transactions

There were no related party transactions in 2004, 2003 or 2002

C. Interests of Experts and Counsel

Not applicable

ITEM 8. Financial Information

A. Consolidated Statements and Other Financial Information

See ITEM 18.

B. Significant Changes

Subsequent to the year ended December 31, 2004, the Trust entered into two material agreements. On April 22, 2005, the Trust entered into a committed equity financing facility with Kingsbridge Capital Limited, pursuant to which Kingsbridge committed, subject to certain significant limitations and conditions precedent, to purchase up to US$100 million of Trust Units. Until April 22, 2007 the Trust may, from time to time, at its sole discretion and subject to various limitations and conditions precedent that the Trust must satisfy, require Kingsbridge to purchase newly-issued Trust Units at a price that is 92% of the volume weighted average of the price of our Trust Units for each of the fifteen trading days following its election to sell, or draw down, Trust Units.

As part of this arrangement, the Trust issued a warrant to Kingsbridge, which entitles Kingsbridge to purchase 301,000 Trust Units at a price of US$25.77 per Trust Unit. The warrant is exercisable beginning April 22, 2005 and until April 22, 2008. The exercise price of the warrant is adjusted downward by the amount of distributions on the Trust Units while the Warrant is exercisable but unexercised to a minimum of US$21.55 per Trust Unit. The warrant also has a cashless exercise feature.

The Trust is under no obligation to access any of the capital available under this commitment. It has the option to draw on the commitment based on 92% of the fifteen day volume weighted average trading price which must exceed $12 per Trust Unit. Under the terms of the commitment, the first draw is to be up to US$10 million and each subsequent draw can be up to 4% of the Trust s market capitalization but not to exceed $25 million per draw. There is to be 20 consecutive trading days between each drawdown. The term of this commitment is 24 months or until the total commitment of $100 million is drawn. In conjunction with the commitment, Kingsbridge will receive warrants to purchase 301,000 Trust Units at an exercise price of $25.77/Trust Unit. The warrants will have a three year term and the exercise price of the warrants will be adjusted downward by the amount of unpaid distributions to a minimum price of US$21.55/Trust Unit. The Trust intends to register the Trust Units for resale as per the agreement. The arrangement is subject to regulatory approval.

On May 30, 2005, the Trust and High Point Resources Inc. entered into an agreement for the acquisition by the Trust of all of the issued and outstanding common shares of High Point. The acquisition is to be completed by way of a plan of arrangement pursuant to which shareholders of High Point will receive for each share of High Point held 0.105 of a Trust Unit. The closing price of the Trust Units on Friday, May 27th was C$25.41, valuing the common shares of High Point at C$2.67 per share. High Point has approximately 85 million shares outstanding. The

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transaction, including assumption of High Point s debt of approximately US$67 million, has been valued at approximately US$250 million. The Trust will be issuing approximately 8.9 million units or approximately 34% of the total number of Trust Units currently outstanding.

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ITEM 9. The Offer and Listing

A. Offer and Listing details

Not applicable, except for Item 9A (4)

Price Range of Common Stock and Trading Markets

On November 28, 2003 the business of Old Enterra was reorganized as an income trust. In conjunction with this reorganization holders of Enterra Energy Corp. common stock received two trust units for each share of common stock held or non-registered exchangeable shares convertible into an equal number of trust units. All historical information before November 28, 2003 in the following tables has been restated to reflect this exchange.

Old Enterra s shares commenced trading on the TSX Venture Exchange (TSXV) under the symbol WLX during the quarter ended September 30, 1998. Our shares traded on the National Quotation Bureau s pink sheets (Pink Sheets) under the symbol WLKSF from April 26, 2000 to January 10, 2001 when the shares commenced trading on the Nasdaq Small Cap Market under the symbol EENC and under the symbol ENT on the TSX Venture Exchange (TSX). On May 21, 2003 the shares commenced trading on the Nasdaq National Market under the symbol EENC. On June 20, 2003 the shares commenced trading on the Toronto Stock Exchange under the symbol ENT . Following our reorganization as an income trust in November 2003 our trust units commenced trading on the Nasdaq National Market and Toronto Stock Exchange under the same symbols as the common stock which was retired as a result of the reorganization.

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The following table sets forth the bid prices, in Canadian or U.S. dollars, as reported by the TSXV, TSX and NASDAQ National and Small Cap Markets/pink sheets, for the periods shown, as restated for periods prior to November 28, 2003 to reflect the 2:1 conversion from common shares to trust units.

	Toronto Stock Exchange/TSX Venture Exchange (Cdn. $ s)		Nasdaq Small Cap Market/Pink Sheets (U.S. $ s)		Nasdaq National Market (U.S. $ s)	
Five most recent full fiscal years:	**High**	**Low**	**High**	**Low**	**High**	**Low**
Year ended December 31, 2004	24.00	13.01	n/a	n/a	19.47	10.10
Year ended December 31, 2003	14.10	4.995	7.75	3.245	10.91	4.625
Year ended December 31, 2002	5.75	1.30	3.75	0.735	n/a	n/a
Year ended December 31, 2001	3.75	1.15	2.405	0.825	n/a	n/a
Year ended December 31, 2000	3.90	2.225	2.305	1.705	n/a	n/a
Year ended December 31, 2004:						
Quarter ended December 31, 2004	24.00	17.64	n/a	n/a	19.47	14.06
Quarter ended September 30, 2004	19.08	16.81	n/a	n/a	15.04	12.65
Quarter ended June 30, 2004	20.70	15.50	n/a	n/a	15.90	11.02
Quarter ended March 31, 2004	21.00	13.01	n/a	n/a	16.19	10.10
Year ended December 31, 2003:						
Quarter ended December 31, 2003	14.10	5.775	n/a	n/a	10.91	4.625
Quarter ended September 30, 2003	12.935	8.54	n/a	n/a	9.625	6.00
Quarter ended June 30, 2003	10.25	8.925	7.75	4.045	n/a	n/a
Quarter ended March 31, 2003	7.00	4.995	4.75	3.245	n/a	n/a
Six most recent months ended:						
December 2004	24.00	19.36	n/a	n/a	19.03	16.47
January 2005	23.65	21.77	n/a	n/a	19.10	17.83
February 2005	26.80	22.03	n/a	n/a	20.95	18.19
March 2005	25.14	21.80	n/a	n/a	20.41	18.19
April 2005	28.84	24.45	n/a	n/a	24.40	20.00
May 2005	27.73	23.01	n/a	n/a	22.49	18.50
June 2005 (through June 15)	29.24	23.85	n/a	n/a	22.21	19.00

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B. Plan of Distribution

Not applicable

C. Markets

See Item 9.A

D. Selling Shareholders

Not applicable

E. Dilution

Not applicable

F. Expenses of the issue

Not applicable

ITEM 10. Additional information

A. Share Capital

Not applicable

B. Trust Indenture / Memorandum and Articles of Association

The Trust

Enterra Energy Trust is an open-ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture.

The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

The Trustee is prohibited from acquiring any investment or engaging in any activity which (a) would result in the Trust Units becoming foreign property (as defined in the *Income Tax Act* (Canada)) or which would cause the Trust to become liable for tax under Part XI under the *Income Tax Act* (Canada), (b) would result in the Trust not being considered either a unit trust or a mutual fund trust for purposes of the *Income Tax Act* (Canada), or (c) would cause the Trust to be subject to regulation as an investment company under the *U.S. Investment Company Act of 1940.*

The Trust is authorized to issue an unlimited number of trust units. The Unitholders have no liability for further capital calls and are not subject to any discrimination due to number of trust units owned.

The rights of trust Unitholders can be changed at any time in a Unitholders meeting where the modifications are approved by 66 2/3% of the Unitholders represented by proxy or in person at the meeting.

All Unitholders are entitled to vote at annual or special meetings of Unitholders, provided that they were Unitholders as of the record date. The record date for Unitholders meetings may precede the meeting date by no more than 50 days and not less than 21 days. Notice of the time and place of meetings of Unitholders may not be less than 21 or greater than 50 days prior to the date of the meeting.

See Additional Information Relating to the Trust.

Enterra

Enterra is amalgamated under the laws of the Province of Alberta, Canada (corporation number 207913385). The Articles of Amalgamation and by-laws provide no restrictions as to the nature of the business operations of Enterra.

The governing legislation requires a director to inform Enterra, at a meeting of the Board of Directors, of any interest he or she has in a material contract or proposed material contract with Enterra. No director may vote in respect of any such contract made by them with Enterra or in any such contract in which they are interested. However, these provisions do not apply to (i) an arrangement by way of security for money lent to or obligations undertaken by them: (ii) a contract relating primarily to their remuneration as a director, officer, employee or agent of Enterra or an affiliate: (iii) a contract for indemnity or insurance of the director as allowed under the governing legislation: or (iv) a contract or transaction with an affiliate.

The Board of Directors, subject to the direction of the Trustee, may exercise all powers of the Trust to borrow or raise money, and to give guarantees, and to mortgage or charge its properties and assets, and to issue debentures, debenture stock and other securities, outright or as security for any debt, liability or obligation of the Trust or its subsidiaries.

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There are no age limit requirements regarding retirement of directors and there is no minimum share ownership required for a director s election to the board.

All directors of Enterra are elected at each annual meeting of Unitholders of the Trust and cumulative voting is not permitted.

C. Material Contracts

The Trust has entered into material contracts that are other than in the ordinary course of business during the previous two years, other than as described elsewhere in this Form 20-F, as follows:

Governing Trust Documents

(a) Trust Indenture The Trust is governed by an amended and restated trust indenture dated November 25, 2003 which is fully described in this Form 20-F under Item 4. Information on the Trust.

(b) Administration Agreement The Trust entered into an administration agreement with Enterra dated November 25, 2003 in connection with the Arrangement (the Administration Agreement). Under the Administration Agreement, Enterra is appointed the administrator of the Trust (the Administrator) and is responsible for the administration and management of all general and administrative affairs of the Trust. The Administrator is not entitled to the payment of a fee for the services provided to the Trust. The Administrator is, however, entitled to be indemnified and saved harmless by the Trust against all losses (other than loss of profit), claims, damages, liabilities, obligations, costs and expenses in any way arising from and related in any manner to the provision of services and the performance of obligations by the Administrator unless found liable for or guilty of fraud, wilful default or negligence.

(c) Enterra Note Indenture Enterra entered into an agreement with Olympia Trust Company dated November 25, 2003 (the Note Indenture) providing for the issuance of unsecured subordinated notes. An unlimited number of notes may be issued under the Note Indenture. The initial series of notes issued were Series A Notes which rank equally in right of payment. The initial principal amount of the Series A Notes issued was $125,000,000 bearing interest at a rate of 14% per annum. Additional Series A Notes may be issued from time to time. Pursuant to the terms of the Note Indenture, and subject to certain restrictions set forth therein, Enterra is entitled to defer the payment of interest on the principal amount of the Series A Notes for periods not exceeding 27 consecutive months. In certain circumstances, Enterra has the ability to make payments in respect of interest and/or principal on the Series A Notes by the issuance of common shares of Enterra. The Note Indenture provides for various events of default with respect to the Series A Notes including, but not limited to, failure to pay interest or principal, acceleration of senior indebtedness of Enterra, failure to perform any other covenant, certain events of bankruptcy or ceasing to carry on in the ordinary course of business.

(d) Support Agreement In connection with the Arrangement, the Trust entered into a support agreement with Enterra dated November 25, 2003 (the Support Agreement) to establish a procedure whereby the Trust would take certain actions and make certain payments and deliveries necessary to ensure that Enterra can make certain payments and deliver Trust Units in satisfaction of its obligations in connection with the Exchangeable Shares issued pursuant to the Arrangement.

Under the Support Agreement, the Trust has agreed that: (a) it will take all actions and do all things necessary to ensure that Enterra is able to pay to the holders of the Exchangeable Shares the Liquidation Amount in the event of a liquidation, dissolution or winding up of Enterra, the Retraction Price in the event of the giving of a Retraction Request by a holder of Exchangeable Shares, or the Redemption Price in the event of a redemption of Exchangeable

Shares by Enterra (as such capitalized terms are defined in the Support Agreement); and (b) it will not vote or otherwise take any action or omit to take any action causing the liquidation, dissolution or winding up of Enterra.

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

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

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

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

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

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

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

With the exception of certain administrative changes, the Support Agreement may not be amended without the approval of the holders of the Exchangeable Shares. The Trust also agreed not to exercise any voting rights attached to the Exchangeable Shares owned by it or any of its respective subsidiaries and other affiliates on any matter considered at meetings of holders of Exchangeable Shares.

(e) Voting and Exchange Trust Agreement The Trust entered into an agreement dated November 25, 2003 with Enterra, Enterra Exchangeco Ltd. (Exchangeco) and Olympia Trust Company, as the initial Trustee (the Voting and Exchange Trust Agreement), pursuant to which the Trust issued a special voting right to the Trustee for the benefit of the holders of the Exchangeable Shares (the Special Voting Right). The Special Voting Right carries a number of votes, exercisable at any meeting at which Unitholders are entitled to vote, equal to the number of Trust Units into which the outstanding Exchangeable Shares are then exchangeable multiplied by the number of votes to which the holder of one Trust Unit is then entitled.

Upon the occurrence and during the continuance of: (a) an Insolvency Event (as defined in the Voting and Exchange Trust Agreement); or (b) circumstances in which the Trust or Exchangeco may exercise certain call rights held by them, but elect not to exercise such call rights;

a holder of Exchangeable Shares will be entitled to instruct the Trustee to exercise the Optional Exchange Right (as defined in the Voting and Exchange Trust Agreement) with respect to any or all of the Exchangeable Shares held by such holder, thereby requiring the Trust or Exchangeco to purchase such Exchangeable Shares from the holder.

The purchase price payable by the Trust or Exchangeco for each Exchangeable Share to be purchased under the Optional Exchange Right will be satisfied by the issuance of that number of Trust Units equal to the Exchange Ratio (as defined in the Voting and Exchange Trust Agreement) as at the day of closing of the purchase and sale of such Exchangeable Share under the Optional Exchange Right.

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

Other Material Contracts

(f) <u>Amended and Restated Agreement of Business Principles</u> The Trust, JED Oil Inc. (JED) and JMG Exploration, Inc. (JMG) are parties to an Amended and Restated Agreement of Business Principles pursuant to which each oil and gas property which is owned by the Trust is as a general matter to be developed or explored under arrangements pursuant to which JED and JMG, respectively, bear the cost thereof in exchange for a percentage (usually 70 percent) of such property and the Trust retains the balance of such property. The Trust has a first right to purchase oil and gas properties owned by JED prior to the sale thereof to others, and the Trust has the right to purchase 80 percent of any oil and gas property that is owned by JMG when drilling has established the existence of commercially viable quantities of oil or gas at a value that is based upon an independent engineering report.

(g) Technical Services Agreement The Trust and JED are parties to a Technical Services Agreement pursuant to which employees of JED may provide administrative, management and technical services to the Trust at the cost of the Trust and the Trust is to provide office space and administrative supplies to JED at the cost of JED.

(h) RMAC Arrangement Agreement The Trust entered into an Arrangement Agreement dated August 20, 2004 for the acquisition of all of the issued and outstanding common shares of Rocky Mountain Energy Corp. (Rocky) completed on September 29, 2004 by plan of arrangement. The acquisition was paid for by the issuance of 1,946,576 Trust Units, 341,882 Exchangeable Shares and cash of C$7,223,746. Each Rocky common share was exchanged for 0.35078 Trust Units, Exchangeable Shares or cash. The acquisition was valued at approximately C$55 million.

(i) RMAC Note Indenture Rocky Mountain Acquisition Corp. entered into an agreement with Olympia Trust Company dated September 28, 2004 (the RMAC Note Indenture) providing for the issuance of unsecured subordinated notes. An unlimited number of notes may be issued under the RMAC Note Indenture. The initial series of notes issued were Series A Notes which rank equally in right of payment. The initial principal amount of the Series A Note issued was $29,153,223 bearing interest at the rate of 11% per annum. Additional Series A Notes may be issued from time to time. Pursuant to the terms of the RMAC Note Indenture, and subject to certain restrictions set forth therein, RMAC is entitled to defer the payment of interest on the principal amount of the Series A Notes for periods not exceeding 27 consecutive months. In certain circumstances, RMAC has the ability to make payments in respect of interest and/or principal on the Series A Notes by the issuance of common shares of RMAC. The RMAC Note Indenture provides for various events of default with respect to the Series A Notes including, but not limited to, failure to pay interest or principal, acceleration of senior indebtedness of RMAC, failure to perform any other covenant, certain events of bankruptcy or ceasing to carry on in the ordinary course of business.

(j) Trust Unit Sale Agreement The Trust entered into an agreement with Kingsbridge Capital Limited (Kingsbridge) on April 22, 2005 for a drawdown equity financing arrangement. Pursuant to this agreement, Kingsbridge agreed to purchase up to $100 million Trust Units over a two year period. The Trust has no obligation to access any of the available capital, but may do so at its option. The subscription price of the Trust Units on each drawdown will be 92% of the fifteen day volume weighted average trading price of the Trust Units on the Nasdaq provided that the price must be at least US$12.00 and not less than the minimum price permitted by the rules of the Toronto Stock Exchange. The first draw may be up to US$10 million, and each subsequent draw can be up to the lesser of 4% of the Trust s market capitalization or US$25 million. The Trust also granted a warrant to Kingsbridge to purchase 301,000 Trust Units which cannot be exercised for three months and thereafter has a three year term. The exercise price of the warrant will initially be US$25.77 per Trust Unit which will be reduced each month by the amount of the Trust s distribution for such month on the Trust Units, provided that the price shall not decrease below US$21.55 per Trust Unit as provided by the Toronto Stock Exchange convertible securities pricing rules.

(k) High Point Arrangement Agreement The Trust signed an arrangement agreement dated May 31, 2005 with High Point Resources Inc. (High Point) to acquire all of the issued and outstanding common shares of High Point to be completed by plan of arrangement (the High Point Plan). High Point shareholders will receive 0.105 of a Trust Unit or Exchangeable Share for each High Point common share held. The value of this transaction is approximately US$250 million and the Trust will issue approximately 8.9 million Trust Units in association with the High Point Plan, which equals approximately 35% of the current issued and outstanding Trust Units. This transaction remains subject to approval by the High Point shareholders at a special meeting which is expected to occur in August 2005.

D. Exchange Controls

There is no law or government decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to non-resident holders of trust units, other than withholding tax requirements.

There is no limitation imposed by Canadian law or by our charter or other charter documents on the right of a non-resident to hold or vote our trust units, other than as provided by the *Investment Canada Act*, the *North American Free Trade Agreement Implementation Act* (Canada) and the *World Trade Organization Agreement Implementation Act*. The *Investment Canada Act* requires notification and, in certain cases, advance review and approval by the Government of Canada of the acquisition by a non-Canadian of control of a Canadian business, each as defined in the *Investment Canada Act*. In general, the threshold for review will be higher in monetary terms for a member of the World Trade Organization or North American Free Trade Agreement.

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E. Taxation

Canadian Federal Income Tax Considerations

The following is a summary of the material Canadian federal income tax considerations under the *Income Tax Act* (Canada) (the Tax Act) in respect of the acquisition of trust units pursuant this offering generally applicable to purchasers who (i) hold trust units as capital property for purposes of the Tax Act, and (ii) at all material times deal at arm s length, and are not affiliated, with Enterra and the Trust for purposes of the Tax Act. Generally, trust units will be considered to be capital property to a holder who does not hold such securities in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Canadian resident Unitholders who might not otherwise be considered to hold their trust units as capital property may, in certain circumstances, be entitled to make an irrevocable election in accordance with subsection 39(4) of the Tax Act to have such trust units treated as capital property.

This summary is not applicable to either a unitholder that is a financial institution or a specified financial institution , as defined for purposes of the Tax Act, or a unitholder, an interest in which would be a tax shelter investment under the Tax Act.

This summary is based upon the provisions of the Tax Act and the regulations thereunder (Tax Regulations) in force as of the date hereof, all specific proposals to amend the Tax Act and the Tax Regulations that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the Proposed Amendments) and the Trust s understanding of the current published administrative and assessing policies of the Canada Revenue Agency (the CRA).

This summary is not exhaustive of all possible Canadian federal income tax considerations applicable to the acquisition of trust units and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law, whether by legislative, governmental or judicial action or changes in the administrative and assessing practices of the CRA. This summary does not take into account any provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be relied on as legal or tax advice or representations to any particular investor. Consequently, potential investors are urged to seek independent tax advice in respect of the consequences to them of the acquisition of trust units having regard to their particular circumstances.

Residents of Canada

This portion of the summary is applicable to a unitholder who, for the purposes of the Tax Act and at all relevant times, is resident, or deemed to be resident, in Canada.

Status of the Trust

The Trust qualifies as a mutual fund trust under the provisions of the Tax Act and the balance of the summary assumes that the Trust will continue to so qualify. The Trust is also a registered investment under the Tax Act, and this summary further assumes that the Trust will be so registered.]

The requirements to qualify as a mutual fund trust for purposes of the Tax Act include:

1. the sole undertaking of the Trust must be the investing of its funds in property (other than real property or interests in real property), the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Trust, or any combination of these

activities;

2. the Trust must comply on a continuous basis with certain requirements relating to the qualification of the trust units for distribution to the public, the number of Unitholders and the dispersal of ownership of trust units. In this regard, there must be at least 150 Unitholders, each of whom owns not less than one block of trust units having a fair market value of not less than $500. A block of trust units means 100 trust units if the fair market value of one trust unit is less than $25; and

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3. continuously from the time of its creation, all or substantially all of the Trust s property must consist of property other than property that would be taxable Canadian property for purposes of the Tax Act.

The Trust has certain restrictions on its activities and its powers and certain restrictions on the holding of taxable Canadian property, such that Enterra believes it is reasonable to expect that the requirements will be satisfied. However, Enterra and the Trust can provide no assurances that the requirements will continue to be met.

If the Trust were not to so qualify as a mutual fund trust or were not to be registered as a registered investment from inception, the income tax considerations would in some respects be materially different from those described below.

Taxation of the Trust

The Trust is subject to tax in each taxation year on its income or loss for the year, computed as though it were a separate individual resident in Canada. The taxation year of the Trust will end on December 31 of each year.

The Trust will be required to include in its income for each taxation year (i) all interest on the Notes that accrues to, becomes receivable or is received by it before the end of the year, except to the extent that such interest was included in computing its income for a preceding year (ii) all interest on the CT Note that accrues to, becomes receivable or is received by it before the end of the year, except to the extent that such interest was included in computing its income for a preceding year (iii) the net income of Commercial Trust paid or payable to the Trust in the year and (iv) all amounts in respect of any oil and gas royalties, if any, held by the Trust including any amounts required to be reimbursed to the grantor of the royalty in respect of Crown charges.

In computing its income, the Trust will generally be entitled to deduct reasonable administrative expenses incurred to earn income. The Trust will be entitled to deduct the costs incurred by it in connection with the issuance of trust units on a five-year, straight-line basis (subject to pro-ration for short taxation years). The Trust may also deduct amounts which become payable by it to Unitholders in the year, to the extent that the Trust has net income for the year after the inclusions and deductions outlined above and to the extent permitted under the Tax Act. An amount will be considered to have become payable to a unitholder in a taxation year only if it is paid in that year by the Trust or the unitholder is entitled in that year to enforce payment of the amount. Under the Trust Indenture, net income of the Trust for each year will be paid or made payable by way of cash distributions to the Unitholders. The Trust Indenture also contemplates other situations in which the Trust may not have sufficient cash to distribute all of its net income by way of such cash distributions. In such circumstances, such net income will be payable to Unitholders in the form of the issuance by the Trust of additional trust units (Reinvested trust units). Accordingly, it is anticipated that the Trust will generally not have any taxable income for the purposes of the Tax Act.

Under the Trust Indenture, income received by the Trust may be used to finance cash redemptions of trust units. A redemption of trust units that is effected by a distribution by the Trust to a unitholder of Series A Notes will be treated as a disposition by the Trust of such Series A Notes for proceeds of disposition equal to the fair market value thereof and may give rise to a taxable capital gain to the Trust.

The Trust will be entitled for each taxation year to reduce (or receive a refund in respect of) its liability, if any, for tax on its net taxable capital gains by an amount determined under the Tax Act based on the redemption or retraction of trust units during the year (the Capital Gains Refund). In certain circumstances, the Capital Gains Refund for a particular taxation year may not completely offset the Trust s tax liability on net realized capital gains for such taxation year.

For purposes of the Tax Act, the Trust generally intends to deduct, in computing its income and taxable income, the full amount available for deduction in each year. As a result of such deductions and the Trust s entitlement to a Capital

Gains Refund, it is expected that the Trust will not be liable for any material amount of tax under the Tax Act. However, no assurance can be given in this regard.

The Trust is a registered investment under the Tax Act. It may have its registration revoked by the CRA if it ceases to be a mutual fund trust and did not otherwise qualify for registered investment status.

If the Trust ceases to qualify as a mutual fund trust, the Trust may be required to pay tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have material adverse tax consequences for certain Unitholders.

Taxation of Unitholders

Income from trust units

The income of a unitholder from the trust units will be considered to be income from property for the purposes of the Tax Act. Any deduction or loss of the Trust for the purposes of the Tax Act cannot be allocated to and treated as a deduction or loss of a unitholder.

A unitholder will generally be required to include in computing income for a particular taxation year of the unitholder the portion of the net income of the Trust for a taxation year, including taxable dividends and net taxable capital gains, that is paid or becomes payable to the unitholder in that particular taxation year, whether such amount is payable in cash or in Reinvested trust units. Provided that appropriate designations are made by Commercial Trust and the Trust, such portion of the Trust s net taxable capital gains and taxable dividends, if any, as are paid or payable to a unitholder will effectively retain their character as taxable capital gains and taxable dividends, respectively, and will be treated as such in the hands of the unitholder for purposes of the Tax Act.

The amount of any net taxable capital gains designated by the Trust to a unitholder will be included in the unitholder s income under the Tax Act for the year of disposition as a taxable capital gain. See *Taxation of Capital Gains and Capital Losses* above. The non-taxable portion of net realized capital gains of the Trust that is paid or becomes payable to a unitholder in a year will not be included in computing the unitholder s income for the year. Any other amount in excess of the net income of the Trust that is paid or becomes payable by the Trust to a unitholder in a year will generally not be included in the unitholder s income for the year. However, a unitholder is required to reduce the adjusted cost base of the trust units held by such unitholder by each amount payable to the unitholder otherwise than as proceeds of disposition of trust units (except to the extent that the amount either was included in the income of the unitholder or was the unitholder s share of the non-taxable portion of the net capital gains of the Trust, the taxable portion of which was designated by the Trust in respect of the unitholder). To the extent that the adjusted cost base of a trust unit is less than zero, the negative amount will be deemed to be a capital gain of a unitholder from the disposition of the trust unit in the year in which the negative amount arises. See *Taxation of Capital Gains and Capital Losses* below.

The amount of dividends designated by the Trust to a unitholder will be subject to, among other things, the gross-up and dividend tax credit provisions for Unitholders who are individuals, the refundable tax under Part IV of the Tax Act applicable to private corporations and subject corporations (as defined under the Tax Act), and the deduction in computing taxable income in respect of dividends received by taxable Canadian corporations. In general, net income of the Trust that is designated as taxable dividends from taxable Canadian corporations or as net taxable capital gains may increase an individual unitholder s liability for alternative minimum tax.

Cost of trust units

The cost to a unitholder of a trust unit will generally include all amounts paid by the unit holder for the trust unit. Reinvested trust units issued to a unitholder, as a non-cash distribution of income will have a cost equal to the amount of income distributed by the issuance of such Reinvested trust units. This cost will be averaged with the adjusted cost base of all other trust units held by the unitholder as capital property in order to determine the respective adjusted cost base of each trust unit.

Disposition of trust units

Upon the disposition or deemed disposition by a unitholder of a trust unit, whether on a redemption or otherwise, the unitholder will generally realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition exceed (or are less than) the aggregate of (i) such unitholder s adjusted cost base of the trust units disposed of, determined immediately before the disposition and (ii) any reasonable costs of disposition. A redemption of trust units in consideration for cash distributed to the unitholder in satisfaction of the Market Redemption Price, or the issuance of a Redemption Note by the Trust in satisfaction of the Market Redemption

Price, will be a disposition of such trust units for proceeds of disposition equal to the cash or the principal amount of the Redemption Note, as the case may be. Where trust units are redeemed by the distribution of Series A Notes to the unitholder, the proceeds of disposition to the unitholder of such trust units will generally be equal to the fair market value of the Series A Notes so distributed less any capital gain or income realized by the Trust in connection with such redemption which has been designated by the Trust to the redeeming unitholder.

Where a unitholder that is a corporation or a trust (other than a mutual fund trust) disposes of a trust unit, the unitholder s capital loss from the disposition will generally be reduced by the amount of dividends from taxable Canadian corporations previously designated by the Trust to the unitholder, except to the extent that a loss on a previous disposition of a trust unit has been reduced by such dividends. Similar rules apply where a corporation or trust (other than a mutual fund trust) is a member of a partnership that disposes of trust units. See *Taxation of Capital Gains and Capital Losses* below.

The cost to a unitholder of any Series A Notes distributed to the unitholder by the Trust on a redemption of trust units will be equal to the fair market value of such Series A Notes at the time of distribution, excluding any accrued interest thereon. Such a unitholder will be required to include in income interest on such Series A Notes (including interest that had accrued to the date of distribution of the Series A Notes to the unitholder) in accordance with the provisions of the Tax Act. To the extent that the unitholder is required to include in income any interest that had accrued to the date of distribution of the Series A Notes, an offsetting deduction will be available in computing the unitholder s income from the Trust.

A unitholder will be required to include in income interest on the Redemption Notes in accordance with the provisions of the Tax Act.

A unitholder that is corporation that is throughout a relevant taxation year a Canadian-controlled private corporation , as defined in the Tax Act, may be liable to pay an additional refundable tax of 6 2/3% on certain investment income, including taxable capital gains and interest.

Tax-Exempt Unitholders

Provided that the Trust qualifies as a mutual fund trust or is a registered investment for purposes of the Tax Act at a particular time, the trust units will be qualified investments for Exempt Plans. If the Trust ceases to qualify as a mutual fund trust and the Trust s registration as a registered investment under the Tax Act is revoked, the trust units will cease to be qualified investments under the Tax Act for Exempt Plans. Where, at the end of a month, an Exempt Plan holds trust units or other properties that are not qualified investments, the Exempt Plan may, in respect of that month, be required to pay a tax under Part XI.1 of the Tax Act.

Exempt Plans will generally not be liable for tax in respect of any distributions received from the Trust or any capital gain arising on the disposition of trust units. However, where an Exempt Plan receives trust property as a result of a redemption of trust units, some or all of such property may not be qualified investments under the Tax Act for the Exempt Plans and could, as discussed above, give rise to adverse consequences to the Exempt Plans (and, in the case of registered retirement savings plans or registered retirement income funds, to the annuitants thereunder). Accordingly, Exempt Plans that own trust units should consult their own tax advisors before deciding to exercise their redemption rights thereunder.

Taxation of Capital Gains and Capital Losses

Generally, one half of any capital gain (a taxable capital gain) realized by a unitholder or a unitholder on the disposition of capital property in a taxation year must be included in the income of the holder for the year, and one half of any capital loss (an allowable capital loss) realized in a taxation year may be deducted from taxable capital gains realized by the holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

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A corporation that is throughout a relevant taxation year a Canadian-controlled private corporation , as defined in the Tax Act, may be liable to pay an additional refundable tax of 6 2/3% on certain investment income, including taxable capital gains realized in the particular taxation year.

Capital gains realized by an individual may give rise to a liability for alternative minimum tax.

Non-Residents of Canada

This portion of the summary is applicable to a unitholder who, for the purposes of the Tax Act, and at all relevant times is not resident in Canada and is not deemed to be resident in Canada, does not use or hold, and is not deemed to use or hold, trust units in, or in the course of, carrying on business in Canada, and is not an insurer who carries on an insurance business in Canada and elsewhere (a Non-Resident Holder).

Taxation of the Trust

The tax treatment of the Trust under the Tax Act is as generally described above under Residents of Canada Taxation of the Trust . If the Trust ceases to qualify as a mutual fund trust for purposes of the Tax Act, the Trust may be required to pay tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse tax consequences to certain Unitholders.

Taxation of Income from Trust Units

All income of the Trust determined in accordance with the Tax Act (except taxable capital gains) paid or credited by the Trust in a taxation year to a Non-Resident Holder will generally be subject to Canadian withholding tax at a rate of 25%, subject to a reduction of such rate under an applicable income tax treaty or convention, whether such income is paid or credited in cash or in Reinvested trust units. See *Residents of Canada Taxation of the Trust* above. Provided that certain conditions are satisfied, the rate of Canadian withholding tax may be reduced to 15% in respect of amounts that are paid or credited by the Trust to a Non-Resident Holder that is a United States resident for the purposes of the Canadian-United States Income Tax Convention.

The Trust is required to maintain a special TCP gains balance account to which it will add its capital gains from dispositions after March 22, 2004 of taxable Canadian property (as defined in the Tax Act) and from which it will deduct its capital losses from dispositions of such property and the amount of all TCP gains distributions (as defined in the Tax Act) made by it in previous taxation years. If the Trust pays an amount to a Non-Resident Holder, makes a designation to treat that amount as a taxable capital gain of the Holder and the total of all such amounts designated by the Trust in a taxation year to Non-Resident Holders exceeds 5% of all such designated amounts, such portion of that amount as does not exceed the Non-Resident Holder s pro rata portion of the Trust s TCP gains balance account (as defined in the Tax Act) for the taxation year effectively will be subject to the same Canadian withholding tax as described above for distributions of income (other than net realized capital gains). All other amounts distributed by the Trust to a Non-Resident Holder other than amounts described above, where more than 50% of the fair market value of a Trust Unit is attributable to, inter alia, real property situated in Canada or a Canadian resource property (as defined in the Tax Act) will be subject to a special Canadian tax of 15% of the amounts of such distributions as an income tax on the deemed capital gain. This tax will be withheld from such distributions by the Trust. A Non-Resident Holder will not be required to report such distribution in a Canadian tax return and such distribution will not reduce the adjusted cost base of the Non-Resident Holder s Trust Units. If a Non-Resident Holder realizes a capital loss on the disposition of a Trust Unit in a particular taxation year and files a special tax return on or before such Non-Resident Holder s filing due date for such taxation year, the Non-Resident Holder will have a Canadian property mutual fund loss (as defined in the Tax Act) equal to the lesser of such loss and sum of all distributions previously received on such Trust Unit that were subject to 15% tax. The Non-Resident Holder s tax liability for such taxation year shall be computed by reducing any deemed capital gain for the taxation year by the aggregate of such loss and any unused Canadian property mutual fund losses (as defined in the Tax Act) from previous taxation years arising from the disposition of a Trust Unit or a share of the capital stock of a mutual fund corporation or a unit of another mutual fund trust. In certain circumstances, the Non-Resident Holder may be entitled to receive a refund of all or a portion of such tax. A Canadian property mutual fund loss and unused Canadian mutual fund losses generally may be carried back up to three years and forward indefinitely and deducted against similar distributions received in such years.

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Disposition of trust units

A Non-Resident Holder will be subject to taxation in Canada in respect of a capital gain or capital loss realized on the disposition of trust units only to the extent such units constitute taxable Canadian property , as defined in the Tax Act, and the Non-Resident Holder is not afforded relief under an applicable income tax treaty or convention.

Trust units will normally not be taxable Canadian property at a particular time provided that (i) the Non-Resident Holder, persons with whom the Non-Resident Holder does not deal at arm s length (within the meaning of the Tax Act), or the Non-Resident Holder together with such persons, did not own or have an interest in or option in respect of 25% or more of the issued trust units at any time during the 60-month period preceding the particular time (ii) the Trust is a mutual fund trust at the time of the disposition, and (iii) the trust units are not otherwise deemed to be taxable Canadian property.

A Non-Resident Holder of trust units that are not taxable Canadian property will not be subject to tax on gains realized under the Tax Act on the disposition of such units.

A Non-Resident Holder whose trust units constitute taxable Canadian property generally will realize a capital gain (or capital loss) on the redemption or disposition of such units equal to the amount by which the proceeds of disposition exceeds (or is less than) the aggregate of (i) such unitholder s adjusted cost base of its trust units so disposed, determined immediately before the disposition and (ii) any reasonable costs of disposition.

Taxation of Capital Gains and Capital Losses on Dispositions of Taxable Canadian Property

Generally, one half of any capital gain (a taxable capital gain) realized by a Non-Resident Holder on a disposition of taxable Canadian property in a taxation year must be included in the income of the Non-Resident Holder for the year, and one half of any capital loss (an allowable capital loss) realized by a Non-Resident Holder on a disposition of taxable Canadian property in a taxation year may be deducted from taxable capital gains realized by the Non-Resident Holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

In certain cases where a Non-Resident Holder realizes a capital gain from a disposition of property that constitute taxable Canadian property to such Non-Resident Holder, it is possible that any such capital gain may be exempt from tax for the purposes of the Tax Act by virtue of the provisions of an income tax treaty or convention between Canada and the country of residence of the Non-Resident Holder. Conversely, the amount of any capital loss resulting from the disposition of such property may not be deductible against capital gains of the Non-Resident Holder for the purposes of the Tax Act by virtue of the provisions of such income tax treaty or convention. Unitholders who are Non-Resident Holders are advised to consult with their tax advisors regarding the application of any applicable income tax treaty or convention.

If a Non-Resident Holder disposes of taxable Canadian property, the Non-Resident Holder is required to file a Canadian income tax return for the taxation year in which such disposition occurs.

United States Federal Income Tax Considerations

The following summary discusses the material United States federal income tax considerations that are generally applicable to a holder of Enterra common shares and trust units who is a citizen or resident of the United States, who is a corporation, partnership or other entity that is created or organized in or under the laws of the United States, who is subject to United States federal income tax on a net income basis with respect to Enterra common shares or who will be subject to United States federal income tax on a net income basis with respect to trust units that are acquired (a U.S. Holder).

This summary does not purport to be a complete description of all of the United States federal income tax considerations that may be relevant to a U.S. Holder. In particular, this summary deals only with U.S. Holders who hold Enterra common shares as a capital asset. This summary does not address the tax treatment of U.S. Holders

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who are subject to special tax rules. Nor does this summary discuss the United States federal income tax considerations for a partner in a partnership which holds Enterra common shares or trust units.

Flow-through of Items of Income, Gain, Loss, Deduction and Credit

A U.S. holder will include in each of its taxable years its share of our items of income, gain, loss, deduction and credit and certain deductions in respect of depletion for each of our taxable years that ends within or with such U.S. holder s taxable year on its own United States federal income tax return in order to determine its liability for United States federal income tax whether or not we make any distribution to it. Such items of income, gain, loss, deduction and credit will be determined on United States federal income tax principles and will as a general matter retain their character and source as they flow through us to the holders of trust units. The use by a holder of trust units of certain of our items of deduction, loss and credit will be limited as is discussed below.

As a result, a U.S. holder whose taxable year is not the same as our taxable year and who disposes of all of its trust units after the close of its taxable year but before the end of our taxable year will be required to include in income for its then taxable year its share of more than one year of our items of income, gain, loss, deduction and credit. A U.S. Holder s share of our items of income, gain, loss, deduction and credit will, as a general matter, be its percentage interest in us of such items.

Tax Rates and Creditability of Certain Canadian Income Taxes.

As general matter, the character and source of a U.S. holder s share of the items of the income, gain, loss, deduction and credit is determined at our level and flows through us to each such U.S. holder in determining its liability for United States federal income tax including any effect of the alternative minimum tax. Each U.S. holder should consult with its tax advisors as to the impact of holding trust units on its liability for the United States federal income tax and the alternative minimum tax. The rules as to the use of foreign income taxes as credits are complex, the following discussion is only a summary of a portion thereof, and a U.S. holder should discuss these matters with its own tax advisors.

United States Federal Income Tax Rates

A U.S. holder s share of our oil and gas production is treated as ordinary income subject to cost depletion. Such ordinary income is generally subject to the income tax at a maximum rate of 35 percent. Dividends that are received from a foreign corporation are currently subject to the United States federal income tax at a maximum rate of 15 percent under certain conditions. If a U.S. holder who is an individual, then any dividends received would be subject to the United States federal income tax at a maximum rate of 15 percent so long as (i) the shares in respect of which the dividends are paid have been held (subject to certain tolling rules) for more than 60 days during the 120 day period which begins 60 days before the those shares go ex-dividend, (ii) such U.S. holder is not under an obligation to make certain related payments with respect to substantially similar or related property, (iii) we are not either a foreign personal holding company, a foreign investment company or a passive foreign investment company, and (iv) we are eligible for the benefits of the income tax treaty between Canada and the United States. It is likely that the Internal Revenue Service will take the position that such holding period requirement is applied when an individual holds shares indirectly through us to the individual s holding period in trust units.

For a U.S. holder who is an individual, any long-term capital gain that is realized on the sale or other disposition of trust units (including any part of a distribution that is treated as gain on such shares that is a long-term capital gain) would be subject to tax at a maximum rate of 15 percent until the end of 2008 under current law. Each U.S. holder should discuss with its own advisor whether a person whose holding period in us is less than one year can claim such 15 percent tax rate.

Credits for Canadian Income Taxes

As a general matter, any Canadian income taxes that are withheld from distributions are foreign income taxes that, subject to generally applicable limitations under United States law, may be used by a U.S. holder as a credit against its United States federal income tax liability or as a deduction (but only for a taxable year for which such U.S. holder elects to do so with respect to all foreign income taxes). So long as we are a partnership for United States federal

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income tax purposes, the provisions of Section 901(k) of the Internal Revenue Code should not apply. If we were a corporation for such purposes, then a U.S. Holder would not be able to claim the foreign tax credit with respect to any such Canadian tax that is withheld on a distribution that we made unless such U.S. holder had held the trust units for a minimum period (subject to certain tolling rules) of at least 16 days during the 30 day period beginning on the date which is 15 days before the date on which the trust units went ex-dividend with respect to such dividend or to the extent such U.S. holder is under an obligation to make related payments with respect to substantially similar or related property. It is likely that the Internal Revenue Service will take the position that the holding period requirement that is summarized in the preceding sentence is measured as to an individual partner of us in respect of any Canadian taxes paid by us in respect of dividends that we receive by the holding period in the trust units.

The limitation under United States law on foreign taxes that may be used as credits is calculated separately with respect to specific classes of income or baskets . That is, the use of foreign taxes that are paid with respect to income in any such basket as a credit is limited to a percentage of the foreign source income in that basket. For such purposes, a U.S. holder s share of our income, gain, loss and deductions is generally in the passive basket if it holds less than 10 percent of the trust units. Its share of the dividends and the income will be from foreign sources, but the amount of foreign source income of an individual is only a fraction of the dividend income that is subject to the 15 percent maximum rate. Under rules of general application, a portion of a U.S. holder s interest expense and other expenses can be allocated to, and thereby reduce, the foreign source income in any basket.

Any gain that is recognized by a U.S. Holder on the sale of a trust unit that is recognized because a distribution thereon is in excess of basis in that security will generally constitute income from sources within the United States for U.S. foreign tax credit purposes and will therefore not increase the ability to use foreign taxes as credits.

Tax Consequences if We are Determined to be a Passive Foreign Investment Company

Although we do not expect to be a passive foreign investment company, or PFIC, it will be a PFIC if either (a) 75 percent or more of its gross income in a taxable year, including the pro rata share of the gross income of any company, U.S. or foreign, in which it is considered to own 25 percent or more of the shares by value, is passive income (as defined in the pertinent provisions of the Internal Revenue Code or (b) 50 percent or more of its assets (including the pro rata share of the assets of any company in which it is considered to own 25 percent or more of the shares by value), are held for the production of, or produce, passive income. Although we believe that we are not currently a PFIC and do not expect that we will become a PFIC, there is no assurance in that regard.

If we were a PFIC, and a U.S. holder did not make an election to treat it as a qualified electing fund (there is no assurance that it will be able to make such an election) or elect to make a mark-to-market election (again, there is no assurance that it will be able to make such an election) then distributions on our stock that exceed 125 percent of the average distributions received by the U.S. holder in the shorter of the three previous taxable years or the U.S. holder s holding period for the trust units before the taxable year of distribution and the entire amount of gain that is realized by a U.S. holder upon the sale of the trust units would be subject to an additional United States income tax that approximates (and in some cases exceeds) the value of presumed benefit of a deferral of United States income taxation that was available because we are a foreign corporation.

Tax-Exempt Organizations and Other Investors

Ownership of trust units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations, other foreign persons and regulated investment companies or mutual funds raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. We are unable to provide any assurance that the income that we recognize in respect of the royalty or in respect of any of our other assets will not be unrelated business taxable income.

A regulated investment company or mutual fund (as such terms are used in the Internal Revenue Code) is required in order to maintain its special status under the Internal Revenue Code to derive 90 percent or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. A significant amount of our gross income may not be any such type of income.

Administrative Matters

Information Returns and Audit Procedures

We expect to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes the unitholder s share of our income, gain, loss, deduction and credits for the preceding taxable year. In preparing this information, which will not be reviewed by tax counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine the share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code Treasury regulations or administrative interpretations of the Internal Revenue Service. Any challenge by the Internal Revenue Service could negatively affect the value of the trust units.

The Internal Revenue Service may audit our federal income tax information returns. Adjustments resulting from an Internal Revenue Service audit may require each unitholder to adjust a prior year s tax liability, and possibly may result in an audit of its return. Any audit of a unitholder s return could result in adjustments not related to our returns. Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the Internal Revenue Service and tax settlement proceedings.

The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the Tax Matters Partner for these purposes. The Tax Matters Partner will make some elections on our behalf and on behalf of Unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against Unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a one percent profits interest in us to a settlement with the Internal Revenue Service unless that unitholder elects, by filing a statement with the Internal Revenue Service, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the Unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least one percent interest in profits or by any group of Unitholders having in the aggregate at least a five percent interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the Internal Revenue Service identifying the treatment of any item on its federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest trust units as a nominee for another person are required to furnish to us:

the name, address and taxpayer identification number of the beneficial owner and the nominee;

whether the beneficial owner is:

(i) a person that is not a United States person;

(ii)

a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

(iii) a tax-exempt entity;

the amount and description of trust units held, acquired or transferred for the beneficial owner; and

specific information including the dates of acquisitions and transfers means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on the trust units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue

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Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the trust units with the information furnished to us.

Registration as a Tax Shelter

The Internal Revenue Code requires that tax shelters be registered with the Secretary of the Treasury. Although we may not be a tax shelter for such purposes, we have applied to register as a tax shelter with the Secretary of the Treasury in light of the substantial penalties that might be imposed if registration is required and not undertaken.

Issuance of a tax shelter registration number does not indicate that investment in us or the claimed tax benefits have been reviewed, examined or approved by the Internal Revenue Service.

We will supply our tax shelter registration number to you when one has been assigned to us. A unitholder who sells or otherwise transfers a trust unit in a later transaction must furnish the registration number to the transferee. The penalty for failure of the transferor of a unit to furnish the registration number to the transferee is $100 for each failure. A unitholder must disclose our tax shelter registration number on its tax return on which any deduction, loss or other benefit we generates is claimed or on which any of our income is included. A unitholder who fails to disclose the tax shelter registration number on its return, without reasonable cause for that failure, will be subject to a $250 penalty for each failure. Any penalties discussed are not deductible for federal income tax purposes.

Reportable Transactions

Certain Treasury regulations require taxpayers to report specific information on Internal Revenue Service Form 8886 if they participate in a reportable transaction . A transaction may be a reportable transaction based upon any of several factors, including the existence of book-tax differences common to financial transactions, one or more of which may be present with respect to your investment in the trust units. Investors should consult their own tax advisor concerning the application of any of these factors to an investment in the trust units. Congress is considering legislative proposals that, if enacted, would impose significant penalties for failure to comply with these disclosure requirements.

Other Tax Considerations

Each U.S. holder is urged to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of acquiring and holding the trust units. Accordingly, each prospective unitholder is urged to consult its tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns that may be required.

F. Dividends and Paying Agents
Not applicable

G. Statement by Experts
Not applicable

H. Documents on Display
Any statement in this annual report about any of our contracts or other documents is not necessarily complete. If the contract or document is filed as an exhibit, the contract or document is deemed to modify the description contained in this registration statement. You must review the exhibits themselves for a complete description of the contract or document.

We intend to provide our Unitholders with annual reports containing consolidated financial statements audited by an independent chartered accounting firm and will make available to Unitholders quarterly reports containing unaudited consolidated financial data for the first three quarters of each year. We are subject to the information and reporting requirements of the Securities and Exchange Act of 1934 and file periodic reports, proxy statements and other information with the SEC. However, we are exempt from the rules under the Exchange Act prescribing the furnishing and content of proxy statements, and our officers, directors and principal stockholders are exempt from the reporting and short-swing profit recovery provisions contained in Section 16 of the Exchange Act. Under the Exchange Act, we are not required to publish financial statements as frequently or as promptly as U.S. companies. Such reports, proxy statements and other information filed with the SEC may be inspected at the public reference facilities maintained by the Commission at Judiciary Plaza, 450 5th Street N.W., Washington, D.C. 20549. Copies of these materials may be obtained at prescribed rates from the Commission at that address. The reports, proxy statements and other information can also be inspected on the Commission s Web site at www.sec.gov

If you are a unitholder, you may request a copy of these filings at no cost by contacting us at:

Enterra Energy Trust
Suite 2600, 500 4th Avenue S.W.
Calgary, Alberta, Canada
T2P 2V6
(403) 213-2502

I. Subsidiary Information
Not applicable

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ITEM 11. Qualitative and Quantitative Disclosures about Market Risk

We are exposed to all of the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in notes 12 and 13 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk

We are exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Our monthly distributions are also based on a value expressed in U.S. dollars. However, we pay our operating expenses, drilling expenses and general overhead expenses in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect us. When the value of the U.S. dollar increases, we receive higher revenue and when the value of the U.S. dollar declines, we receive lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to CDN dollar would impact Enterra s earnings by approximately $500,000 and our cash flow by $400,000.

Commodity Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on our earnings would be approximately $1,300,000 and the impact on our cash flow would be approximately $2,000,000. If natural gas prices were to change by US$0.50 per mcf, the impact on our earnings would be approximately $800,000 and the impact on our cash flow would be approximately $1,200,000.

We periodically use hedges with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits which may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2004, we had $43.9 million of indebtedness bearing interest at floating rates. If interest rate were to change by one full percentage point, the net impact on our earnings would be approximately $300,000 and the net impact on our cash flow would be approximately $400,000.

Summarized below are our sensitivities to various risks, based on its 2004 operations:

Sensitivities		**Estimated 2005 impact on:**	
		Net Earnings	**Cash Flow**
Crude oil	US$1.00/bbl change in WTI	$ 1,300,000	$ 2,000,000

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Sensitivities		**Estimated 2005 impact on:** Net Earnings	**Cash Flow**
Natural Gas	US$0.50/mcf change	$ 800,000	$ 1,200,000
Foreign Exchange	$0.01 change in U.S. to CDN dollar	$ 500,000	$ 400,000
Interest rate	1% change	$ 300,000	$ 400,000

ITEM 12. Description of Securities Other Than Equity Securities

Not applicable

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Part II

ITEM 13. Defaults, Dividends Arrearages and Delinquencies

None

ITEM 14. Material Modifications to the Rights of Security Holders and Use of Proceeds

Not applicable

ITEM 15. Controls and Procedures

(a) Disclosure controls and procedures.

Our Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report (the Evaluation Date), have concluded that, as of the Evaluation Date, our disclosure controls and procedures were adequate and effective to ensure that material information relating us and our consolidated subsidiaries would be made known to them by others within those entities.

(b) Management s annual report on internal control over financial reporting.

Not applicable

(c) Attestation report of the registered public accounting firm.

Not applicable

(d) Changes in internal controls.

There were no significant changes in our internal controls or in other factors that could significantly affect our disclosure controls and procedures subsequent to the Evaluation Date, nor were there any significant deficiencies or material weaknesses in such disclosure controls and procedures requiring corrective actions. As a result, no corrective actions were taken. With the addition of new executive officers and senior staff, and with the ongoing growth of the Trust s business, the internal control systems will continue to evolve.

ITEM 16. **[Reserved]**

ITEM 16A. **Audit Committee Financial Expert**

The chairman of our audit committee, William E. Sliney, is independent in accordance with applicable Nasdaq listing standards and the rules and regulations of the SEC and possesses the attributes required of an audit committee financial expert as defined by ITEM 16A(b) of Form 20-F.

ITEM 16B. **Code of Ethics**

We have adopted a Code of Ethics which applies to all directors, officers, employees and consultants. Our code of ethics is posted on our website at www.enterraenergy.com.

ITEM 16C. **Principal Accountant Fees and Services**

Audit Fees

Our principal accountants, KPMG LLP, audited our annual financial statements for the 2004 fiscal year. Deloitte & Touche LLP audited our annual financial statements for 2003 fiscal year. The audit fees for 2004 were $292,986 (2003 $248,050). Audit fees are fees billed for the audit of our annual consolidated financial statements and statutory and regulatory filings.

Audit-Related Fees

Our principal accountants billed audit-related fees for 2004 of $21,130 (2003 nil). These fees were for the reviews of our interim financial statements.

Tax Fees

Our principal accountants billed tax fees for 2004 of $12,500 (2003 $22,000). These fees were for the reviews of our tax statements regarding our distributions.

All Other Fees

Our principal accountants billed other fees for 2004 of $nil (2003 nil). These fees were for the reviews of our financing and acquisition related filings.

Pre-Approval Policies and Procedures

The audit committee pre-approves all audit, audit-related services, tax services and other services provided by our principal accountants. Any services provided by our principal accountants that are not specifically included within the scope of the audit must be pre-approved by the audit committee in advance of any engagement. Under the Sarbanes-Oxley Act of 2002, audit committees are permitted to approve certain fees for audit-related services, tax services and other services pursuant to a de minimus exception prior to the completion of an audit engagement.

ITEM 16D. **Exemptions from the Listing Standards for Audit Committees**

Not applicable.

ITEM 16E. **Purchases of Equity Securities by the Issuer and Affiliated Purchasers**

Not applicable.

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PART III

ITEM 17. Financial Statements

We have responded to Item 18 in lieu of responding to this item.

ITEM 18. Financial Statements

The Consolidated Financial Statements of Enterra Energy Trust are attached as follows:

Audited Annual Financial Statements:

Reports of Deloitte & Touche LLP and KPMG LLP, Independent Auditors
Consolidated Balance Sheets
Consolidated Statements of Earnings and Accumulated Earnings
Consolidated Statements of Cash Flows
Notes to Consolidated Financial Statements

ITEM 19. Exhibits

Number	Exhibit
2.1	Amalgamation Agreement dated May 27, 1998 between Temba Resources Ltd. and PTR Resources Ltd. pursuant to which the Registrant was amalgamated under the Business Corporations Act (Alberta) on June 30, 1998.[1]
2.2	Letter Agreement dated August 12, 1999 pursuant to which the Registrant acquired all of the issued and outstanding shares of 759795 Alberta Ltd.[2]
2.3	Notice of Intention to File a Normal Course Issuer Bid.[3]
3.1	Certificate of Amalgamation and attached Articles of Amalgamation of the Registrant dated and filed June 30, 1998.[4]
3.2	By-laws of the Registrant.[5]
3.3	Enterra Energy Trust Amended And Restated Trust Indenture.[6]
4.1	Amendment Agreement to the Trust Unit Purchase Agreement.[7]
4.2	Form of Warrant Agreement between the Registrant and the Representatives providing for the issuance of the Underwriters Warrants.[8]
4.3	Credit Facility Letter Agreement between the Alberta Treasury Branches and the Registrant as Borrower dated April 19, 2000.[9]
4.4	Promissory Notes dated June 5, 2000 granted by Westlinks to each of Glenn Russell, Patrick Williams Advisors, William J. Gordica, F. Jack Wright, Lawrence W. Underwood and Sapphire Capital Inc.[10]
4.5	Purchase and Sale Agreement dated April 6, 2000 between Sabre Exploration Ltd. and the Registrant.[11]
4.6	Consulting Agreement dated October 13, 2000 between Westlinks Resources Ltd. and Wells Gray Resort & Resources Ltd.[12]
4.7	Arrangement Agreement among Westlinks Resources Ltd. and 3779041Canada Ltd. and Big Horn Resources Ltd.[13]
4.8	Note Indenture.
4.10	Administration Agreement.
4.13	Second Amended and Restated Agreement of Business Principles.
4.14	Technical Services Agreement.
4.15	Arrangement Agreement.
4.16	Trust Unit Purchase Agreement.
12.1	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
12.2	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
13.1	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act
13.2	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act

99.1	Consent from KPMG LLP
99.2	Consent from Deloitte & Touche LLP
99.3	Consent from McDaniel & Associates Consultants Ltd.

1 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.1, filed with the SEC 2000-06-21 (No. 333-39826).

2 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.2, filed with the SEC 2000-06-21 (No. 333-39826).

3 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.3, filed with the SEC 2000-06-21 (No. 333-39826).

4 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 3.1, filed with the SEC 2000-06-21 (No. 333-39826).

5 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 3.2, filed with the SEC 2000-06-21 (No. 333-39826).

6 Incorporated by reference to the Company s Registration Statement on Form 8-A12G/A, filed 2003-11-28 (No. 000-32115).

7 Incorporated by reference to the Company s Form 6-K dated July 15, 2005.

8 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.2, filed with the SEC 2000-06-21 (No. 333-39826).

9 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.3, filed with the SEC 2000-06-21 (No. 333-39826).

10 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.4, filed with the SEC 2000-06-21 (No. 333-39826).

11 Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.5, filed with the SEC 2000-06-21 (No. 333-39826).

12 Incorporated by reference to the Company s Registration Statement on Form F-1/A, Exhibit 4.6, filed with the SEC 2000-12-01 (No. 333-39826)

13 Incorporated by reference to the Company s Annual Report on Form 20-F, Exhibit 1, filed with the SEC on 2001-06-18 (No. 000-32115).

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Auditors Report to the Unitholders

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Enterra Energy Trust

We have audited the accompanying consolidated balance sheet of Enterra Energy Trust as of December 31, 2004 and the consolidated statements of earnings and accumulated earnings and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Trust s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Trust as of December 31, 2004 and the results of its operations and its cash flows for year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2003 and for each of the two years ended December 31, 2003, prior to the adjustments for the change in the Trust s accounting policy for asset retirement obligations as described in note 3(c) to the consolidated financial statements, were audited by another firm of chartered accountants who expressed an opinion without reservation on those statements in their audit report dated March 5, 2004. We have audited the adjustments to the financial statements as at December 31, 2003 and for each of the two years ended December 31, 2003 as described in note 3(c) to the consolidated financial statements and in our opinion, such adjustments, in all material aspects, are appropriate and have been properly applied.

Canadian generally accepted accounting principles vary in certain significant respects from accounting principles generally accepted in the United States of America. Information relating to the nature and effect of such differences is presented in notes 17 and 18 to the consolidated financial statements.

(Signed) KPMG LLP
Chartered Accountants
Calgary Canada
March 31, 2005, except for notes 16(d), 16(e), 16(f), 17 and 18 which are as of June 30, 2005

Comments by Auditor for US Readers on Canada-US Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principle that has a material effect on the comparability of the Trust s financial statements, such as the changes described in note 3 to the Trust s consolidated financial statements as at and for the year ended December 31, 2004. Our report to the unitholders dated March 31, 2005, except for notes 16(d), 16(e), 16(f), 17 and 18 which are as of June 30, 2005, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors report when the changes are properly accounted for and adequately disclosed in the financial statements.

(Signed) KPMG LLP
Chartered Accountants
Calgary Canada
June 30, 2005

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REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Trustees and the Unitholders of Enterra Energy Trust:

We have audited the consolidated balance sheet of Enterra Energy Trust (formerly Enterra Energy Corp.) as at December 31, 2003 and the consolidated statements of earnings and accumulated earnings and cash flows for each of the years in the two year period ended December 31, 2003 prior to the adjustments for the change in the Trust s accounting policy for asset retirement obligations as described in Note 3(c). These financial statements are the responsibility of the Trust s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements, prior to the adjustments for the change in the Trust s accounting policy for asset retirement obligations as described in Note 3(c), present fairly, in all material respects, the financial position of Enterra Energy Trust as at December 31, 2003 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust s internal control over financial reporting. Accordingly we express no such opinion.

(signed) Deloitte & Touche LLP

Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Alberta, Canada
March 5, 2004 (except for Note 17(g) which is as of June 17, 2005)

Comments by Independent Registered Chartered Accountants on Canada-United States of America Reporting Differences

The standards of the Public Company Accounting Oversight Board (United States) require the addition of a explanatory paragraph (following the opinion paragraph) when there has been a restatement of the financial statements as described in Note 17(g) to the consolidated financial statements. Our report to the Board of Trustees and the Unitholders, dated March 5, 2004 (except for Note 17(g) which is as of June 17, 2005), is expressed in accordance with Canadian reporting standards which do not require a reference to such conditions and events in the auditors report when these are adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP

Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Alberta, Canada
March 5, 2004 (except for Note 17(g) which is as of June 17, 2005)

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Enterra Energy Trust
Consolidated Balance Sheets
As at December 31
(Expressed in thousand Canadian Dollars)

	2004	2003
		(restated see note 3(c))
Assets		
Current assets		
Cash	**$ 4,779**	$ 66
Accounts receivable	**15,613**	8,742
Prepaid expenses and deposits	**518**	462
	20,910	9,270
Deposit on land purchase (notes 4 and 16)	**2,400**	2,015
Property and equipment (note 6)	**146,910**	105,253
Deferred financing charges	**90**	123
Goodwill (note 5)	**29,991**	
	$ 200,301	$ 116,661
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 8,570**	$ 12,208
Due to JED Oil Inc. (note 1)	**4,493**	
Distributions payable to unitholders	**4,398**	2,451
Income taxes payable	**1,068**	120
Bank indebtedness (note 8)	**43,930**	33,960
Current portion of capital lease (note 9)	**805**	783
	63,264	49,522
Asset retirement obligations (note 7)	**14,836**	2,188
Future income tax liability (note 11)	**21,526**	13,936
Capital lease (note 9)	**2,580**	3,386
	102,206	69,032
Unitholders Equity		
Unitholders capital (note 10)	**111,653**	32,838
Exchangeable units (note 10)	**3,273**	3,457
Contributed surplus (note 10)	**78**	
Accumulated earnings	**27,903**	13,785

Accumulated distributions	**(44,812)**	(2,451)
	98,095	47,629
Commitments, contingencies and guarantees (notes 13, 14 and 15)		
Subsequent events (note 16)		
	$ 200,301	$ 116,661

Approved on behalf of the Board

Reg Greenslade Director	Bill Sliney Director

See accompanying notes to consolidated financial statements

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Enterra Energy Trust
Consolidated Statements of Earnings and Accumulated Earnings
Years Ended December 31,
(Expressed in thousand Canadian Dollars)

	2004	2003	2002
		restated see note 3(c)	restated see note 3(c)
Revenue			
Oil and gas	**$ 108,293**	$ 72,097	$ 25,746
Expenses			
Royalties	**24,527**	17,656	4,203
Production	**23,492**	12,763	6,018
General and administrative	**4,440**	3,385	1,683
Interest	**2,222**	1,749	1,236
Amortization of deferred financing charges	**33**	262	390
Depletion, depreciation and accretion	**35,438**	23,306	9,449
Financial derivative loss	**3,188**		
Gain on redemption of preferred shares			(3,111)
Restructuring charges (note 1)		5,756	
	93,340	64,877	19,868
Earnings before income taxes	**14,953**	7,220	5,878
Income taxes (reduction) (note 11)			
Current	**260**	134	132
Future	**(71)**	1,988	865
	189	2,122	997
Net earnings	**14,764**	5,098	4,881
Accumulated earnings, beginning of year, as previously stated	**13,937**	8,933	3,956
Change in accounting policy related to asset retirement obligations (note 3(c))	**(152)**	(246)	96
Change in accounting policy related to unit based compensation (note 3(d))	**(646)**		
Accumulated earnings, end of year	**$ 27,903**	$ 13,785	$ 8,933
Earnings per unit (note 10)			
Basic	**$ 0.63**	$ 0.27	$ 0.27

Diluted	**$**	**0.63**	$	0.27	$	0.26

See accompanying notes to consolidated financial statements

Enterra Energy Trust
Consolidated Statements of Cash Flows
Years Ended December 31
(Expressed in thousand Canadian Dollars)

	2004	2003	2002
		(restated see note 3(c))	(restated see note 3(c))
Cash provided by (used in):			
Operations			
Net earnings	**$ 14,764**	$ 5,098	$ 4,881
Add non-cash items:			
Depletion, depreciation and accretion	**35,438**	23,306	9,449
Future income taxes	**(71)**	1,988	865
Amortization of deferred gain		(238)	(524)
Amortization of deferred financing charges	**33**	262	390
Unit based compensation	**78**		
Gain on redemption of preferred shares			(3,111)
Valuation of warrants		282	
Expenditures on asset retirement obligations		(5)	(49)
	50,242	30,693	11,901
Change in non-cash working capital items:			
Accounts receivable	**(4,393)**	(1,429)	(1,017)
Prepaid expenses	**(57)**	195	(74)
Accounts payable and accrued liabilities	**(3,607)**	(8,453)	11,672
Income taxes payable	**160**	(35)	(8)
	42,345	20,971	22,474
Financing			
Distributions paid	**(40,414)**		
Bank indebtedness	**2,305**	9,523	6,028
Due to JED Oil Inc.	**2,400**		
Capital lease	**(783)**	(753)	4,704
Deferred financing charges		(101)	(550)
Redemption of preferred shares		(637)	(2,557)
Issue of trust units, net of issue costs	**36,838**		
Repurchase of shares			(60)
Exercise of options and warrants		6,284	97
	346	14,316	7,662
Investing			
Property and equipment additions	**(30,409)**	(51,577)	(35,881)

Deposit on land purchases	**(385)**	(2,015)	
Proceeds on disposal of property and equipment	**1,178**	18,263	5,810
Acquisition of Rocky Mountain Energy Corp. (note 5)	**(8,362)**		
	(37,978)	(35,329)	(30,071)
Increase (decrease) in cash	**4,713**	(42)	65
Cash, beginning of year	**66**	108	43
Cash, end of year	**$ 4,779**	$ 66	$ 108

During 2004, the Trust paid $2,222,000 (2003 - $1,749,000; 2002 - $1,236,000) of interest on long-term debt and bank indebtedness and nil of capital taxes (2003 - $134,000; 2002 - $132,000).

See accompanying notes to consolidated financial statements

Enterra Energy Trust
Notes to Consolidated Financial Statements
As at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

1. Structure of the Trust and Basis of Presentation

Enterra Energy Trust (the Trust) was established on November 25, 2003 under a Plan of Arrangement involving the Trust, Enterra Energy Corp. (Enterra), Big Horn Resources Ltd., Enterra Production Partnership and Enterra Saskatchewan Ltd. (Plan of Arrangement). The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the Trust Indenture). The beneficiaries of the Trust are the holders of the Trust Units (the Unitholders).

Under the Plan of Arrangement, the shareholders of Enterra exchanged their shares for two Trust Units or two Exchangeable Shares, which may be exchanged into Trust Units. Under the Plan of Arrangement, Enterra became a wholly owned subsidiary of the Trust, through amalgamation of Enterra, Big Horn Resources Ltd. and Enterra Saskatchewan Ltd. on November 25, 2003.

Prior to the implementation of the Plan of Arrangement, the consolidated financial statements included the accounts of Enterra and its subsidiaries. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis, which recognizes the Trust as the successor entity to Enterra. Accordingly, these consolidated financial statements reflect the financial position, results of operations and cash flows as if the Trust, (together with its wholly-owned subsidiaries), had always carried on the business formerly carried on by Enterra with all assets and liabilities recorded at the carrying values of Enterra.

Restructuring costs associated with the Plan of Arrangement totaled $5,756,000 that included legal, accounting and advisory costs of $2,057,000 and employee bonus payments of $3,699,000.

Relationship with JED Oil Inc.

Effective January 1, 2004, the Trust and JED Oil Inc. (JED) entered into a Technical Services Agreement, which provides for services required to manage the Trust s field operations and governs the allocation of general and administrative expenses between the two entities. Under the Technical Services Agreement, the Trust and JED allocate the costs of management, development, exploitation, operations and general and administrative activities on the basis of production and capital expenditures, or as otherwise agreed to between the Trust and JED. The Technical Services Agreement has no set termination date and can be cancelled with six months notice.

Under an Agreement of Business Principles, properties acquired by Enterra will be contract operated and drilled by JMG Exploration, Inc. (JMG), if they are exploration properties, and contract operated and drilled by JED if they are development projects. Exploration of the properties will be done by JMG, which will pay 100% of the exploration costs to earn a 70% working interest in the properties. If JMG discovers commercially viable reserves on the exploration properties, Enterra will have the right to purchase 80% of JMG s working interest in the properties at a fair value as determined by independent engineers. Should Enterra elect to have JED develop the properties, development will be done by JED, which will pay 100% of the development costs to earn 70% of the interests of both JMG and Enterra. Enterra will have a first right to purchase assets developed by JED.

On December 23, 2004, JED loaned to Enterra $2,400,000. The terms of the loan call for interest calculated at a Canadian chartered bank prime lending rate plus 0.4% per annum. The loan is repayable on or before June 29,

2005. Subsequent to December 31, 2004, JED loaned additional funds of $9,600,000 under the same terms. On March 18, 2005, Enterra repaid the original loan amount of $2,400,000 together with accrued interest. At December 31, 2004, Enterra owed $2,093,000 to JED for general and administrative expenses and capital expenditures paid by JED on behalf of Enterra s joint venture partners.

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Enterra Energy Trust
Notes to Consolidated Financial Statements
As at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

2. Significant Accounting Policies

Management of the Trust has prepared the consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements, and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

These consolidated financial statements include the accounts of the Trust, its wholly owned subsidiaries Enterra Energy Commercial Trust, Rocky Mountain Acquisition Corp., Enterra Energy Corp. and Enterra s 100% partnership interest in Enterra Production Partnership (collectively the Trust for purposes of the following notes to the consolidated financial statements). All material inter-company accounts and transactions have been eliminated.

Substantially all exploration, development and production activities related to the Trust s oil and gas business are conducted jointly with others and the accounts reflect only the Trust s proportionate interest.

(b) Cash

Cash consists of cash on hand and balances invested in short-term securities with original maturities less than 90 days.

(c) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when the title passes from the Trust to its customers.

(d) Petroleum and natural gas properties

The Trust follows the full cost method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of oil and gas reserves are capitalized into a single cost center. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells and production equipment.

General and administrative costs are capitalized if they are directly related to successful acquisitions or capital projects.

Proceeds from the disposal of oil and natural gas properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a 20% change in the depletion rate.

Repair and maintenance costs are expensed as incurred.

Enterra Energy Trust
Notes to Consolidated Financial Statements
As at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(e) Impairment Test

The Trust places a limit on the carrying value of property and equipment, which may be depleted against revenues of future periods (the ceiling test). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of petroleum and natural gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs are discounted using a risk-free interest rate. The carrying value of property and equipment subject to the ceiling test includes asset retirement costs.

(f) Per Unit Amounts

Per unit amounts are calculated using the weighted average number of units (or common shares to November 24, 2003) and reflect the two for one exchange ratio pursuant to the Plan of Arrangement. The Trust follows the treasury stock method to determine dilutive effect of options and other dilutive instruments. Under the treasury stock method, only in-the-money dilutive instruments impact the diluted calculations.

(g) Estimates and Assumptions

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the reporting periods.

The amounts recorded for depletion, depreciation and the asset retirement obligation are based on estimates. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

(h) Depletion and Depreciation

The provision for depletion and depreciation of petroleum and natural gas properties is calculated using the unit-of-production method based on the Trust s share of estimated proved reserves before royalties. Natural gas reserves and production are converted to equivalent units of crude oil using their approximate relative energy content.

(i) Goodwill

The Trust recognizes goodwill relating to acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair value of the Trust is compared to its book value. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value to the Trust s identifiable assets and liabilities as if it had been acquired in a business combination for a purchase price equal to its fair market value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment.

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Enterra Energy Trust

Notes to Consolidated Financial Statements

As at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(j) Asset Retirement Obligations

The Trust recognizes a liability for the estimated fair value of the future retirement obligations associated with property and equipment. The fair value of the estimated asset retirement obligations is recorded as a liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The Trust estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability.

(k) Income Taxes

The Trust is a taxable entity under the Canadian Income Tax Act and is taxable only on income that is not distributed or distributable to the Trust s unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Canadian Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

The Trust s corporate subsidiaries follow the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized based on the differences between the amounts reported in the financial statements of the Trust s corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(l) Derivative Financial Instruments

The Trust uses derivative financial instruments such as collars and swaps to manage its exposure to commodity price fluctuations. The Trust uses the fair value method for reporting derivative financial instruments whereby a derivative financial instrument is recorded as an asset or a liability on the balance sheet, and changes in the fair value relating to a financial period are charged to net earnings and net earnings per unit for the period.

(m) Trust Unit Compensation Plans

The Trust has a unit based compensation plan, which is described in note 10. Compensation expense associated with the unit based compensation plan is recognized in earnings over the vesting period of the plan with a corresponding increase in contributed surplus. Any consideration received upon the exercise of the unit-based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in unitholders capital. Compensation expense is based on the fair value of the unit-based compensation at the date of grant using a Black-Scholes option-pricing model.

(n) Deferred Financing Charges

Deferred financing charges relating to a capital lease are being amortized over the term of the capital lease. A total of $164,000 was initially deferred with a remaining $90,000 to be amortized until the end of the lease.

(o) Foreign Currency Transactions

Transactions completed in United States dollars are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in United States dollars are reflected in the financial statements at the Canadian equivalent at the rate of exchange prevailing at the balance sheet date. Translation gains and losses are included in earnings.

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Enterra Energy Trust
Notes to Consolidated Financial Statements
As at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

(p) Office Furniture and Equipment

Office furniture and equipment is depreciated on a 20% declining balance basis.

(q) Comparative Figures

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

3. Changes in Accounting Policies

(a) Full Cost Accounting

Effective January 1, 2004, the Trust prospectively adopted new Canadian accounting standards relating to full cost accounting for oil and gas entities, as outlined in note 2. The new standard modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There was no write down of the Trust s property and equipment as at January 1, 2004, as a result of adopting this standard.

(b) Derivative Financial Instruments

On January 1, 2004, the Trust prospectively adopted new Canadian accounting standards relating to accounting for derivative financial instruments. The new standards establish certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the derivative financial instrument relating to a financial period can either reduce or increase net earnings and net earnings per trust unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments.

The following table summarizes the changes in the financial derivative liability and the deferred financial derivative loss accounts during the year.

Financial Derivative Liability at January 1, 2004	$	958
Financial instruments settled		(3,188)
Mark to market realized loss		2,230
Financial Derivative Liability at December 31, 2004	$	
Deferred Financial Derivative Loss at January 1, 2004	$	958

Amortization of deferred financial loss		(958)
Deferred Financial Derivative Loss at December 31, 2004	$	

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(c) Asset Retirement Obligations

Effective January 1, 2004, the Trust retroactively adopted with restatement of prior periods, new Canadian accounting standards relating to asset retirement obligations as outlined in note 2. Prior to adopting the new standard, the Trust recognized a provision for future site restoration costs over the life of the oil and natural gas properties using a unit-of-production method.

The following tables summarize the changes resulting from this restatement.

Balance Sheet as at December 31, 2003	Balance as previously reported	Adjustments	Balance as restated
Property and equipment	$ 104,821	$ 432	$ 105,253
Asset retirement obligations	1,529	659	2,188
Future income tax liability	14,011	(75)	13,936
Accumulated earnings	13,937	(152)	13,785

Statement of Earning for the year ended December 31, 2003	Balance as previously reported	Adjustments	Balance as restated
Depletion, depreciation and accretion	$ 23,447	$ (141)	$ 23,306
Future income tax expense	1,941	47	1,988
Net earnings	5,004	94	5,098
Net earnings per unit basic and diluted	$ 0.26	$ 0.01	$ 0.27

Statement of Earning for the year ended December 31, 2002	Balance as previously reported	Adjustments	Balance as restated
Depletion, depreciation and accretion	$ 9,307	$ 142	$ 9,449
Future income tax expense	911	(46)	865
Net earnings	4,977	(96)	4,881

Net earnings per unit	basic	$	0.27	$	0.27
Net earnings per unit	diluted	$	0.26	$	0.26

(d) Unit-based compensation

Effective January 1, 2004, the Trust adopted the fair value method of accounting for options on a retroactive basis, without prior period adjustments. In the past, the Trust measured stock option compensation cost based on the intrinsic value of the award at the date of issuance. As the exercise price and the market price were the same at the date of grant, no compensation expense was recognized on any option issuance. In 2003, the Trust disclosed pro forma net earnings and earnings per unit as if the compensation expense for the Trust s unit-based compensation plan had been determined based on the fair value at the date of grant for awards made under the plan subsequent to January 1, 2002.

As a result of the adoption of this policy, the Trust has recorded a charge to accumulated earnings of $646,000 as at January 1, 2004 to reflect the cost related to options granted in 2002 and 2003. In 2004, the earnings of the Trust were reduced by $78,000 as a result of this change in policy.

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4. Property Acquisition

On January 30, 2004, the Trust acquired certain oil and natural gas properties in East Central Alberta for net consideration of $19,609,000. Results from operations of the East Central Alberta assets acquired subsequent to January 30, 2004 are included in the Trust s consolidated financial statements. At December 31, 2003, the Trust had made a refundable deposit on the property purchased in the amount of $2,015,000.

5. Corporate Acquisition

On September 29, 2004, the Trust acquired all of the issued and outstanding shares of Rocky Mountain Energy Corp. for $49,524,000, through its subsidiary Rocky Mountain Acquisition Corp. (RMAC). The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets, including cash of $16,270	$ 2,493
Property and equipment	36,008
Goodwill (with no tax base)	29,990
Current liabilities	(2,849)
Bank indebtedness	(7,665)
Assets retirement obligations	(793)
Future income tax liability	(7,660)
	$ 49,524
Cost of acquisition:	
Cash	$ 7,234
RMAC Exchangeable Units (341,882 issued)	6,147
Trust Units (1,946,576 issued)	34,999
Transaction costs	1,144
	$ 49,524

The purchase price allocation is preliminary and subject to change.

Results from operations of Rocky Mountain Energy Corp. subsequent to September 29, 2004 are included in the Trust s consolidated financial statements.

The value assigned to each Enterra Trust Unit of Cdn $17.98 was based on the weighted average trading price on the NASDAQ National Market System immediately prior to and after the measurement date.

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6. Property and Equipment

			2004
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 221,551	$ 75,967	$ 145,584
Office furniture and equipment	2,158	832	1,326
	$ 223,709	$ 76,799	$ 146,910

			2003
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	$ 145,878	$ 41,601	$ 104,277
Office furniture and equipment	1,603	627	976
	$ 147,481	$ 42,228	$ 105,253

During 2004, $869,000 of general and administrative expenses were capitalized and included in the cost of the petroleum and natural gas properties (2003 - $1,787,000, 2002 - $1,451,000).

Included in petroleum and natural gas properties are assets acquired and pledged under capital lease agreements with a cost base of $5,218,000 and net book value of $3,107,000 (2003 - $5,218,000 and $4,268,000).

At December 31, 2004 costs of undeveloped land of $3,430,000 (2003 - $5,037,000) were excluded from the calculation of depletion expense.

The Trust completed a ceiling test calculation at December 31, 2004 to assess the recoverable value of the petroleum and natural gas properties. The petroleum and natural gas prices are based on the January 1, 2005 commodity price forecast of our independent reserve engineers. These prices have been adjusted for commodity price differentials specific to the Trust. The following table summarizes the benchmark prices used in the ceiling test calculation.

Year	WTI Oil ($U.S./bbl)	Foreign Exchange Rate	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/GJ)
2005	42.00	1.2048	49.60	6.45
2006	39.50	1.2048	46.60	6.20
2007	37.00	1.2048	43.50	6.05
2008	35.00	1.2048	41.10	5.80
2009	34.50	1.2048	40.50	5.70
2010	34.30	1.2048	40.20	5.60
Escalate Thereafter	2.0% per year		2.0% per year	Average 2.0% per year

A ceiling test write down as at December 31, 2004 was not required.

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7. Asset Retirement Obligations

The asset retirement obligations were estimated by management based on the Trust s working interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At December 31, 2004, the Trust estimated the asset retirement obligation to be $14,836,000 (2003 $2,188,000), based on a total future liability of $25,354,000 (2003 - $4,220,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 20 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a credit-adjusted risk-free interest rate of 8%.

The following table reconciles the asset retirement obligations:

	2004	2003
Asset retirement obligation, beginning of year	**$ 2,188**	$ 3,090
Increases in liabilities during the year related to:		
Acquisitions	**10,512**	
Additions	**262**	744
Revisions	**1,128**	
Accretion expense	**867**	112
Dispositions	**(121)**	(1,753)
Liabilities settled during the year		(5)
Asset retirement obligation, end of year	**$ 14,836**	$ 2,188

8. Bank indebtedness

Bank indebtedness represents the outstanding balance under lines of credit totaling $45,000,000 (2003 - $34,650,000). The credit facility consists of two revolving lines of credit of $36,000,000 and $5,000,000, and a demand subordinated debt facility of $4,000,000. Drawings on the revolving facility bear interest at 1.6% above the bank s prime lending rate and the subordinated debt facility bears interest at prime plus 2.0%. Bankers acceptance fees are originally set at 165 basis points and are subject to adjustment up or down prospectively, on a three month basis as determined by the Trusts consolidated debt to cash flow ratio. Security is provided by a first charge over all of the Trust s assets. The amount available under the subordinated debt facility will decrease by $1,000,000 each month until April 30, 2005.

The credit facilities are subject to review by the lenders. Such review is scheduled for completion prior to May 31, 2005. The outcome of the review is not yet determinable.

As at December 31, 2004, the Trust was not in compliance with certain non-financial covenants of its credit facility. The Trust is seeking a waiver of these covenants from its lenders.

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9. Capital Lease Obligation

Description	**2004**	2003
Capital lease bearing interest at 8.605%, repayable monthly at $88,802, including interest. The lease term is for 60 months, due October 1, 2007, with a purchase option of $1,000,000 and secured by the related equipment	**$ 3,385**	$ 4,125
Capital lease that bore interest at 12.15%, repayable monthly at $4,448 including interest. The lease term was 24 months due December 19, 2004 with a purchase option of $100 and secured by the related equipment		44
	3,385	4,169
Less current portion	**(805)**	(783)
	$ 2,580	$ 3,386

Interest expense includes $327,000 (2003 - $358,000; 2002 - $106,000) related to the capital leases.

10. Unitholders Equity

Authorized Trust Units

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture.

Issued Trust Units

	Number of Units/Shares	Amount
Balance at December 31, 2001	18,301,244	$ 29,568
Issued upon exercise of options and warrants	51,406	97
Balance at December 31, 2002	18,352,650	$ 29,665
Issued upon exercise of options and warrants	2,598,906	6,283
Contributed surplus transferred on exercise of warrants		347
Issued pursuant to plan of arrangement:		
Shares exchanged for exchangeable shares and cancelled	(2,000,000)	(3,465)
Shares exchanged for trust units and cancelled	(18,951,556)	(32,831)
Trust units issued	18,951,556	32,831
Issued for exchangeable shares	4,404	8

Balance at December 31, 2003	18,955,960	$ 32,838
Adopt fair value method of unit based compensation (note 3(d))		646
Issued pursuant to private placements	2,699,400	37,676
Issued pursuant on acquisition of Rocky Mountain Energy Corp.	1,946,576	34,999
Issued for exchangeable shares	1,824,864	6,331
Unit share issue costs		(837)
Balance at December 31, 2004	25,426,800	$ 111,653

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Pursuant to the Plan of Arrangement, 18,951,556 Trust Units and 2,000,000 Exchangeable Shares were issued on November 25, 2003 at a two for one exchange ratio and upon cancellation of all outstanding common shares of Enterra. The consideration attributed to the Trust Units and the Exchangeable Shares was the relative proportion of the carrying value of the common shares of Enterra prior to the exchange. The prior year s number of shares issued in the share tables above have been restated to reflect the two for one exchange ratio under the Plan of Arrangement.

Issued Exchangeable Shares

	Enterra Exchangeable Shares	RMAC Exchangeable Shares	Total Exchangeable Shares	Amount
Issued pursuant to Plan of Arrangement	2,000,000		2,000,000	$ 3,465
Exchanged for trust units	(4,404)		(4,404)	(8)
Balance at December 31, 2003	1,995,596		1,995,596	3,457
Issued on acquisition of Rocky Mountain Energy Corp.		341,882	341,882	6,147
Exchanged for trust units	(1,584,826)	(199,438)	(1,784,264)	(6,331)
Balance at December 31, 2004	410,770	142,444	553,214	$ 3,273

The exchangeable shares are convertible at any time into Trust Units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the Trust Units divided by the ten day weighted average unit price preceding the distribution payment date. Cash distributions are not paid on the exchangeable shares. On the third anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of the Trust, or at the Trust s option when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000, the Exchangeable Shares will be redeemed for Trust Units at a redemption price per exchangeable share equal to the value of that number of Trust Units equal to the exchange ratio as at that Redemption Date. The exchangeable shares of the Company are not listed for trading on an exchange.

During 2004, a total of 1,784,264 exchangeable shares were converted into 1,824,864 trust units at an exchange ratio prevailing at the time of conversion (2003 4,404 exchangeable shares were converted into 4,404 Trust Units).

At December 31, 2004, the exchange ratio for Enterra Energy Corp. exchangeable shares was 1.10534 and the exchange ratio for Rocky Mountain Acquisition Corp. was 1.02466.

Contributed surplus

Balance at December 31, 2002	$	65
Value assigned to 200,000 warrants		282
Transfer on exercise of warrants		(347)
Balance at December 31, 2003	$	
Trust unit option based compensation		78
Balance at December 31, 2004	$	78

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Trust unit options

Enterra has granted trust unit options to directors, officers, employees and consultants of the Trust and JED. Each trust unit option permits the holder to purchase one trust unit at the stated exercise price. All options vest over a 3-year period and have a term of 5 years. At the time of grant, the exercise price is equal to the market price.

Prior to November 25, 2003, Enterra had granted options to purchase common shares to directors, officers, employees and consultants. Each option permitted the holder to purchase one common share of Enterra at the stated exercise price. All options vested over a 4-year period and had a term of 5 years. At the time of grant, the exercise price was equal to the market price. Pursuant to the Plan of Arrangement, a total of 899,453 options vested and were exercised at prices ranging from $4.00 to $18.58.

The following options have been granted:

	Number of Options		Weighted-average exercise price
Balance at December 31, 2001	800,000	$	4.00
Options granted	232,000		5.30
Options exercised	(44,511)		3.84
Options cancelled	(115,786)		4.03
Balance at December 31, 2002	871,703	$	4.35
Options granted	31,500		15.74
Options exercised	(899,453)		4.74
Options cancelled	(3,750)		4.41
Balance at December 31, 2003		$	
Options granted	950,000		14.22
Balance at December 31, 2004	950,000	$	14.22
Exercisable at December 31, 2004		$	

Estimated fair value of stock options

The estimated fair value of options was determined using the Black-Scholes model under the following assumptions:

	2004	2003	2002
Weighted-average fair value of options granted ($/option)	**$ 0.33**	$ 7.75	$ 2.83
Risk-free interest rate (%)	**3.8**	5.0	5.0
Estimated hold period prior to exercise (years)	**5**	5	5
Expected volatility (%)	**21**	50	55
Expected cash distribution yield (%)	**11**	Nil	Nil

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Pro forma net earnings fair value based method of accounting for options

In 2003, had the Trust recorded compensation cost for the Trust s unit-based compensation plan based on the fair value at the grant date for awards made under the plan subsequent to January 1, 2002, consistent with the fair value method of accounting for stock-based compensation, the Trust s earnings and earnings per unit for options granted in 2004 and 2003 would have been as follows:

	2004	2003	2002
Net earnings, as reported	**$ 14,764**	$ 5,098	$ 4,881
Deduct:			
Stock-based employee compensation expense determined under fair value based method for all awards		(631)	(47)
Pro forma net earnings	**$ 14,764**	$ 4,467	$ 4,834
Pro forma net earnings per unit basic and diluted	**$ 0.63**	$ 0.24	$ 0.26

Reconciliation of Earnings per Unit Calculations

For the year ended December 31, 2004

	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	$ 14,764	23,327,728	$ 0.63
Options assumed exercised		950,000	
Units assumed purchased		(716,943)	
Diluted	$ 14,764	23,560,785	$ 0.63

For the year ended December 31, 2003 the weighted average number of units outstanding was 18,953,968. There were no options outstanding as at December 31, 2003 and therefore no dilution to earnings per unit for 2003

For the year ended December 31, 2002

	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	$ 4,881	18,308,982	$ 0.27
Options assumed exercised		1,607,998	
Units assumed purchased		(1,091,766)	
Diluted	$ 4,881	18,825,214	$ 0.26

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Warrants

	Number of Warrants	Weighted Average Price
Balance, December 31, 2001	1,100,000	US$3.67
Issued pursuant to debt financing	100,000	US$2.60
Expired	(1,000,000)	US$3.50
Balance, December 31, 2002	200,000	US$4.00
Issued pursuant to debt financing agreement amendment	200,000	US$3.65
Exercised pursuant to Plan of Arrangement	(400,000)	US$3.83
Balance, December 31, 2003		$

During 2003, 200,000 warrants with a weighted average exercise price of $3.65 were granted to an arm s length United States based consulting firm in connection with a potential debt financing in the United States. The fair value was determined using the Black Scholes Option Pricing model using an interest rate of 5% and a volatility factor of 50%. At the May, 2003 shareholders meeting, the terms were amended to provide for immediate vesting of these warrants as of the April 16, 2002 date of the agreement. The estimated fair value of the warrants of $282,000 was expensed in 2003.

Trust Unit Savings Plan

In 2004, the Trust established a Trust Unit Savings Plan whereby the Trust will match an employee s contributions to the plan to a maximum of 9.0% of their salary. Both the employee s and the Trust s contributions are used to purchase Trust Units on the NASDAQ National Markets system. During the year the Trust expensed approximately $23,000 relating to the Trust s contributions to the plan.

11. Income Taxes

The income tax provision is calculated by applying Canadian federal and provincial statutory tax rates to pre-tax income with adjustments as set out in the following table:

	2004	2003	2002
Earnings before income taxes	**$ 14,953**	$ 7,220	$ 5,878
Combined federal and provincial income tax rate	**38.87%**	40.75%	42.12%

Computed income tax provision	**5,812**	2,942	2,476
Increase (decrease) resulting from:			
Interest component of trust distributions	**(7,038)**	(723)	
Resource allowance	**(4,669)**	(3,260)	(1,627)
Non-deductible crown royalties, net of ARTC	**5,239**	5,412	1,313
Value of warrants expensed for book purposes		115	
Effect of change in tax pools		(1,247)	
Effect of reduction in corporate tax rates		(1,579)	
Non-taxable portion of capital gains			(1,311)
Capital taxes	**260**	134	132
Other	**585**	328	14
	$ 189	$ 2,122	$ 997

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

	2004	2003
Future income tax assets:		
Non-capital loss carry-forwards	**$ 12,127**	$
Asset retirement obligation	**4,988**	760
Unit issue costs	**179**	399
	$ 17,294	$ 1,159
Future income tax liabilities:		
Property and equipment	**38,820**	15,095
Net future income tax liability	**$ 21,526**	$ 13,936

Non-capital loss carry-forwards expire from time to time to 2011.

12. Financial instruments

The Trust s financial instruments recognized on the consolidated balance sheets include cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, income taxes payable, bank indebtedness and long-term debt. The fair values of financial instruments other than the capital lease approximate their carrying amounts due to the short-term nature of the instruments. The carrying value of bank indebtedness approximates its fair value due to floating interest terms; the fair value of the capital lease approximates its carrying value due to current rates for comparable terms of long-term debt.

Due to the nature of its operation, the Trust is exposed to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. The Trust recognizes these risks and manages its operations to minimize the exposure to the extent practical and, to a lesser extent, using derivative instruments. The Trust uses non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. Management monitors the Trust s exposure to the above risks and regularly reviews its derivative activities and all outstanding positions.

(a) Commodity prices risks

The Trust s most significant market risk exposure relates to crude oil prices fluctuation. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent the Trust is also exposed to natural gas price movements. Natural gas prices are generally influenced by North American supply and demand, and to a lesser extent local market conditions.

The Trust has previously entered into derivative financial instruments and fixed price physical contracts to minimize the risk of exposure to fluctuations in the crude oil and natural gas prices. At December 31, 2004, the Trust did not have any derivative financial instruments or fixed price physical sales contracts in place.

(b) Foreign currency exchange risk

The Trust is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(c) Credit risk

A substantial portion of the Trust s accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Trust s natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

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(d) Interest rate risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2004, the Trust had $43,930,000 of indebtedness bearing interest at floating rates and $3,386,000 of capital lease bearing interest at a fixed rate.

13. Commitments

The Trust has commitments for the following payments over the next five years and thereafter:

	2005	2006	2007	2008	2009	2010
Minimum capital lease payments	$ 806	$ 877	$ 1,702	$	$	$
Imputed interest	260	188	97			
Capital lease obligations	1,066	1,065	1,799			
Rental payments re-office space	796	741	640	661	662	28
	$ 1,862	$ 1,806	$ 2,439	$ 661	$ 662	$ 28

During 2004 total rental expense was $81,339 (2003 - $ 299,000; 2002 - $241,000).

14. Contingencies

On October 24, 2003, a statement of claim was filed with the Court of Queen s Bench of Alberta against Enterra in the amount of approximately $12.0 million or as proven by trial. The claimant is requesting the Trust complete a property purchase that Enterra had ended negotiations for in 2003. The Trust has filed a statement of defense and a counter claim. At December 31, 2004, the eventual outcome of this claim is not determinable.

15. Guarantees

The Trust has indemnified all of the directors and officers of the Trust and all the officers, directors, shareholders, employees and agents of JED. There is no pending litigation or proceeding for which a claim is being sought, nor is the Trust aware of any threatened litigation that may result in claims.

16. Subsequent events

(a) On January 26, 2005 the Trust closed an acquisition of petroleum and natural gas properties for cash consideration of $12,303,000. At December 23, 2004, the Trust had made a refundable deposit on the property purchased in the amount of $2,400,000.

(b) The Trust has a bonus plan that is subject to unitholder approval at the 2005 annual general meeting. If the plan is approved by the Unitholders, officers and former officers, directors, employees and consultants of the Trust will be paid bonuses aggregating $1.6 million. As payment of this amount is subject to unitholder approval it has not been accrued in the 2004 financial statements.

(c) On February 20, 2005 the Trust completed a private placement of 500,000 Trust Units at a price of US$19.00 per unit for gross proceeds of US $9,500,000.

(d) On February 22, 2005 the Trust and Enterra Energy Corp. entered into a Letter of Intent with Rocky Mountain

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Gas, Inc. whereby the companies would merge under Wyoming law and Enterra would acquire all the outstanding shares of Rocky Mountain Gas, Inc. Consideration consisted of US $14 million by the issuance of exchangeable shares (exchangeable on a one-to-one basis into trust units), US $5.5 million by the issuance of trust units and US$0.5 million in cash.

(e) On April 27, 2005, the Trust announced an arrangement with Kingsbridge Capital Limited whereby Kingsbridge has committed to purchase U.S.$100 million Enterra trust units. The Trust is not obligated to access any of the capital available under this commitment yet has an option to draw on this commitment through installments for a period of 24 months or until the $100 million is fully drawn. In conjunction with the agreement, Kingsbridge will receive 301,000 warrants to purchase Trust Units at initially U.S.$25.77 per trust unit.

(f) On May 31, 2005, the Trust and High Point Resources Inc. (High Point) entered into an agreement for the acquisition by the Trust of all of the issued and outstanding shares of High Point. The acquisition is anticipated to be completed by way of a plan of arrangement pursuant to which shareholders of High Point will receive 0.105 of a trust unit for each share of High Point. The Trust anticipates issuing 8.9 million trust units in conjunction with the acquisition. The acquisition is subject to regulatory and High Point shareholder approval.

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America

The Trust s consolidated financial statements have been prepared in Canadian Dollars and in accordance with generally accepted accounting principles in Canada (Canadian GAAP), which differ in some respects from those in the United States of America (U.S. GAAP). Any differences in accounting principles as they pertain to the consolidated financial statements as at December 31, 2004 and 2003 and for each of the years in the three year period ended December 31, 2004 were insignificant except as described below:

(a) Property and equipment

Under Canadian GAAP, the Trust performs an impairment test that limits the capitalized costs of its oil and natural gas assets to the discounted estimated future net revenue from proved and probable oil and natural gas reserves using forecasted prices plus the costs of unproved properties less impairment. The discount rate used is a risk free interest rate. Under U.S. GAAP, the full cost method of accounting for oil and natural gas activities require the Trust to perform an impairment test using after tax future net revenue from proved oil and natural gas reserves discounted at 10%. The prices and costs used under the U.S. GAAP ceiling test are those in effect at year-end. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in the year and subsequent years.

There were ceiling test impairments recognized under U.S. GAAP at December 31, 2004 and 2001. No impairment existed at December 31, 2003 or 2002. At December 31, 2004 the Trust recognized a U.S. GAAP ceiling test write-down of $10.0 million ($6.3 million after tax) and at December 31, 2001 a write-down of $28.7 million ($17.5 million after tax).

As a result of these write-downs, the 2004 combined depletion and ceiling test expense under U.S. GAAP was higher than depletion for Canadian GAAP by $8.0 million ($4.9 million after tax) and lower for 2003 and 2002 (2003 - $5.7 million; ($3.4 million after tax); 2002 - $3.6 million; ($2.1 million after tax)).

(b) Financial instruments

Prior to the Trust adopting AcG-13 in 2004 for Canadian GAAP purposes, a difference existed in that under U.S. GAAP, SFAS 133, Accounting for Derivative Instruments and Hedging Activities requires

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that all derivative instruments be recorded on the consolidated balance sheet as either an asset or liability measured at fair value, and requires that changes in fair value be recognized in income unless specific hedge accounting criteria are met. Hedge accounting requires that an entity formally document, designate and assess the effectiveness of derivative instruments before it can use this accounting treatment.

Effective January 1, 2004, the Trust adopted Canadian standards with respect to financial instruments which are similar to SFAS 133. Upon adoption of the Canadian standards the fair value of the Trust s financial instruments was recorded on the balance sheet at January 1, 2004 with a corresponding deferred charge, which was fully amortized in 2004 being the term of the contracts. The $1.0 million ($0.6 million after tax) amortization of the deferred charge recorded in 2004 under Canadian GAAP has been reversed as this amount was recognized in 2003 under U.S. GAAP.

The Trust did not have any derivative instruments or hedging contracts outstanding at December 31, 2004. At December 31, 2003 for U.S. GAAP purposes, the Trust recognized the negative fair value of outstanding financial instruments of $1.0 million ($0.6 million after tax). The financial instruments were not formally documented and designated as hedging relationships and as such were not eligible for hedge accounting treatment.

At December 31, 2002 under Canadian GAAP, the Trust had a deferred gain of $0.2 million ($0.1 million after taxes) that was being amortized over the term of the contract and resulted from the settlement of a fixed contract. Under U.S. GAAP, this gain, net of income taxes, was included in income in 2001, as it did not qualify for hedge accounting under SFAS 133.

The Trust has routinely entered into commodity contracts to minimize its exposure to fluctuations in commodity prices relating to its future sales of crude oil. While such contracts meet the criteria of SFAS 133 as derivatives they are eligible for the normal purchase and sale exception under SFAS 138, Accounting for Certain Derivative Instrument and Certain Hedging Activities An Amendment of SFAS 133 . Contracts that meet the criteria for exception are not recognized on the balance sheet as either an asset or liability measured at fair value. The negative fair value of such contracts at December 31, 2003 was $0.7 million (2002 $0.6 million). There were no such contracts outstanding at December 31, 2004.

(c) Unit-based compensation

Prior to 2004, the Trust accounted for unit-based compensation under the recognition and measurement provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related Interpretations. No stock-based compensation costs were reflected in the 2003 and 2002 net earnings for options granted to employees, as all options granted to employees had an exercise price equal to the market value of Trust Units on the date of grant.

Effective January 1, 2004, the Trust adopted the fair value recognition provisions of SFAS 123, Accounting for Stock-Based Compensation . Under the modified prospective method of adoption selected by the Trust, compensation cost recognized in 2004 is the same as that which would have been recognized had the recognition provisions of SFAS 123 been applied from its original effective date. Results for prior years have not been restated.

Under Canadian GAAP, on January 1, 2004 the Trust adopted similar standards as SFAS 123. On adoption in 2004, $0.6 million of accumulated stock-based compensation expense for the period from January 1, 2002 to the date of adoption was charged to accumulated earnings and an offsetting decrease entered to unitholders equity. Under U.S. GAAP there is no such charge.

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The following table illustrates the effect on net earnings and earnings per share if the fair value based method had been applied to all outstanding and unvested awards to employees in each period.

	2003	2002
Net earnings, as reported	$ 6,510	$ 6,748
Less: Total stock-based employee compensation expense determined under fair value based method for all awards	(737)	(110)
Pro forma net earnings	$ 5,773	$ 6,638
Earnings per unit:		
Basic - as reported	$ 0.34	$ 0.37
Basic - pro forma	$ 0.30	$ 0.36
Diluted - as reported	$ 0.34	$ 0.36
Diluted - pro forma	$ 0.30	$ 0.35

During 2001, the Trust granted 119,500 stock options to non-employees. The value associated with these stock options was $0.1 million for U.S. GAAP purposes. There was no value assigned to these non-employee options for Canadian GAAP purposes.

(d) Earnings

Under U.S. GAAP interest and amortization of deferred financing charges would be presented in the non-operating section of the statement of earnings.

(e) Comprehensive Income

There are no items that would be part of Comprehensive Income other than net income.

(f) Asset Retirement Obligations (ARO)

Effective January 1, 2004, the Trust retroactively adopted the Canadian standards for accounting for asset retirement obligations and prior periods were restated. These standards are equivalent to SFAS No. 143, *Accounting for Asset Retirement Obligations*, for fiscal periods beginning on or after January 1, 2003 except that the transitional provisions between Canadian and U.S. GAAP differ, as Canadian GAAP requires a restatement of comparative amounts whereas U.S. GAAP does not allow restatement.

The adoption of SFAS 143 in 2003 resulted in a cumulative effect of change in accounting principle in the consolidated statement of earnings of a loss of $1.1 million, net of income taxes of $0.6 million. Under the U.S. GAAP accounting rules, the Trust s results would have been as follows:

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	2002
Net earnings - US GAAP	
As reported	$ 6,748
Cumulative effect of change in accounting principle	
Depreciation, depletion, amortization and accretion, net of tax	(202)
Adjusted	$ 6,546
Earnings per unit/share	
Basic as reported	$ 0.37
Adjusted	$ 0.36
Diluted as reported	$ 0.36
Adjusted	$ 0.35

Had SFAS 143 been applied during all periods presented, the asset retirement obligation would have been reported as follows for U.S. GAAP:

January 1, 2002	$ 1,913
December 31, 2002	$ 3,090
December 31, 2003	$ 2,188

In September 2004, the SEC issued SAB 106 concerning SFAS 143. The bulletin outlines the requirement to eliminate the impact of asset retirement from the estimated present value of net revenues prior to conducting the ceiling test calculation. The requirement is made necessary as a result of the adoption of SFAS 143 by the Trust. The Trust has complied with the requirement of SAB 106.

(g) Unitholders Mezzanine equity

Under Canadian GAAP, the Trust Units are considered to be permanent equity and are presented as Unitholders Capital. A U.S. GAAP difference exists due to the redemption feature attached to each trust unit. The Trust Units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of Series A Notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

Previously, U.S. GAAP accounting treatment for trust units was based on the assessment that the redemption feature was sufficiently restrictive to avoid classification as mezzanine equity. This assessment was based upon industry practice and standard industry interpretation of EITF D-98: Classification and Measurement of Redeemable Securities prevailing at the date of the prior year balance sheet. Subsequently industry practice has changed and the Trust has concluded that the redemption feature causes the Trust Units to be classified as mezzanine equity.

Accordingly the Trust has reclassified its Unitholders Capital, both trust units and exchangeable shares, as Mezzanine Equity to meet U.S. GAAP requirements. Mezzanine Equity is valued at an amount equal to the redemption value of the trust units at the balance sheet date. Prior year comparative balances have been restated to conform to this presentation. Any increase or decrease in the redemption value during a period is charged to accumulated earnings and reflected in the calculation of net income per trust unit.

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As at December 31, 2004, Unitholders Capital was reduced by $111.1 million and Exchangeable units was reduced by $3.3 million (2003 - $32.8 million and $3.5 million, respectively) and the redemption value of the trust units and exchangeable units of $529.8 million (2003 - $261.8 million) was recorded as Mezzanine Equity. The increase in the redemption value of the trust units and exchangeable units for the year ended December 31, 2004 of $189.9 million (2003 - $225.4 million, 2002 - Nil) was recorded as a reduction in accumulated earnings.

As a result of adopting this presentation as at November 25, 2003, the date the Trust was formed, Trust Unitholders Capital decreased by $32.8 million, Exchangeable units decreased by $3.5 million, Mezzanine Equity increased by $245.8 million and accumulated earnings decreased by $209.4 million.

(h) Balance sheets

The adjustments using U.S. GAAP would result in the following changes to the consolidated balance sheets of the Trust:

		2004		2003
	Cdn. GAAP	**U.S. GAAP**	Cdn. GAAP (restated)	U.S. GAAP. (restated)
Assets:				
Current assets	**$ 20,910**	**$ 20,910**	$ 9,270	$ 9,270
Deposit on land purchase	**2,400**	**2,400**	2,015	2,015
Property and Equipment (a)(f)	**146,910**	**117,940**	105,253	84,288
Goodwill	**29,991**	**29,991**		
Deferred financing charges	**90**	**90**	123	123
	$ 200,301	**$ 171,331**	$ 116,661	$ 95,696
Liabilities:				
Current liabilities	**$ 63,264**	**$ 63,264**	$ 49,522	$ 49,522
Capital lease	**2,580**	**2,580**	3,386	3,386
Financial derivative liabilities (b)				958
Future income taxes (a) (b) (f)	**21,526**	**10,614**	13,936	5,644
Asset retirement obligation (f)	**14,836**	**14,836**	2,188	2,188
	102,206	**91,294**	69,032	61,698
Mezzanine equity (g)		**529,764**		261,810
Unitholders equity:				
Unitholder s equity (g)	**111,653**		32,838	
Exchangeable units (g)	**3,273**		3,457	
Contributed surplus	**78**	**78**		

Accumulated earnings (deficit)	**27,903**	**(404,993)**	13,785	(225,361)
Accumulated distributions	**(44,812)**	**(44,812)**	(2,451)	(2,451)
	98,095	**80,037**	47,629	33,998
	$ 200,301	**$ 171,331**	$ 116,661	$ 95,696

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(i) Income statements

The adjustments using U.S. GAAP would result in the following changes to the consolidated statement of earnings of the Trust:

	2004	2003 (restated)	2002 (restated)
Net earnings under Canadian GAAP	**$ 14,764**	$ 5,098	$ 4,881
Adjustments:			
Hedging gain (b)		(238)	(524)
Related income taxes		97	221
Depletion and accretions (a)	**(8,005)**	5,676	3,583
Related income taxes	**3,011**	(2,312)	(1,509)
Implementation of ARO for Canadian GAAP (f)		(141)	141
Related income taxes		46	(45)
Unrealized loss on financial instruments (b)	**958**	(958)	
Related income taxes	**(390)**	390	
Net earnings before undernoted items under U.S. GAAP	**10,338**	7,658	6,748
Cumulative effect of change in accounting principle FAS #143 (f)		(1,756)	
Related income taxes		608	
Net earnings under U.S. GAAP before change in redemption value of trust units	**10,338**	6,510	6,748
Change in redemption value of trust units	**(189,970)**	(225,424)	
Net earnings under U.S. GAAP after change in redemption value of trust units	**($179,632)**	($218,914)	$ 6,748
Net earnings per unit/share before under noted items under US GAAP:			
Basic	**$ 0.44**	$ 0.40	$ 0.37
Diluted	**$ 0.44**	$ 0.40	$ 0.36
Net earnings per unit/share relating to change in accounting principle:			
Basic		$ (0.06)	
Diluted		$ (0.06)	
Net earnings per unit/share under US GAAP -before change in redemption value of trust units:			
Basic	**$ 0.44**	$ 0.34	$ 0.37
Diluted	**$ 0.44**	$ 0.34	$ 0.36
Net earning (loss) per unit/share under U.S. GAAP -after change in redemption value of Trust Units:			

Basic	**$**	**(7.70)**	$	(11.55)	$	0.37
Diluted	**$**	**(7.62)**	$	(11.55)	$	0.36

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(j) Additional disclosure under U.S. GAAP

As at December 31	**2004**	2003
Components of accounts receivable		
Trade	**$ 8,095**	$ 8,475
Accruals	**9,014**	267
Allowance for doubtful accounts	**(1,496)**	
	$ 15,613	$ 8,742

As at December 31	**2004**	2003
Components of prepaid expense		
Prepaid expenses	**$ 278**	$ 263
Funds on deposit	**240**	199
	$ 518	$ 462

As at December 31	**2004**	2003
Components of accounts payable		
Accounts payable	**$ 3,928**	$ 10,046
Accrued liabilities	**4,642**	2,162
	$ 8,570	$ 12,208

(k) Cash flows

Under Canadian GAAP, reporting entities are permitted to present a sub-total prior to changes in non-cash working capital within operating activities. This information is perceived to be useful information for various users of the financial statements and is commonly presented by Canadian public companies. Under U.S. GAAP, this sub-total is not permitted to be shown and would be removed in the statements of cash flows for all periods presented.

(l) Pro forma information (unaudited)

The following unaudited pro forma summary information provides an indication of what the Trust s results of operation might have been had the acquisition of Rocky Mountain Energy Corp. (note 5) taken place on January 1, 2004 and 2003 under both Canadian and U.S. GAAP.

	2004 (unaudited)		2003 (unaudited)	
	Cdn. GAAP	**U.S. GAAP**	Cdn. GAAP	U.S. GAAP
Revenue	**$ 122,474**	**$ 122,474**	$ 88,894	$ 88,894
Net earnings before change in redemption value of trust units and the effect of accounting changes	**$ 11,166**	**$ 12,583**	$ 4,760	$ 6,824
Cumulative effect of accounting changes	**$**	**$**	$	$ (1,281)
Net earnings (loss)	**$ 11,166**	**$ (177,387)**	$ 4,760	$ (247,098)
Earnings (loss) per trust unit basic	**$ 0.45**	**$ (7.08)**	$ 0.22	$ (11.63)
Earnings (loss) per trust unit diluted	**$ 0.44**	**$ (7.02)**	$ 0.22	$ (11.63)

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18. New Accounting Pronouncements

The following standards issued by the FASB do not impact us at this time:

(a) In December 2004, FASB issued statement 123R Share Based Payments that establishes the standards for the accounting for transactions in which an entity exchanges its equity for goods or services. The statement focused primarily on the accounting for transactions in which an entity obtains employee services in exchange for share-based consideration. The statement establishes a standard to account for such transactions using a fair-value-based method. The effective date for implementation of this standard would be the first interim or annual period beginning on or after June 15, 2005 for transactions entered into on or after the effective date. Management has not yet assessed the impact if any, of this standard on its consolidated financial statements.

(b) In December 2004, SFAS issued statement No. 153 Exchanges for Non-monetary Assets an amendment of APB Opinion No. 29. The statement eliminates the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary exchanges that do not have commercial substance. A non-monetary exchange is defined as having commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. Management does not expect this statement to have a material impact on this consolidated financial statements

The Trust will continue to assess the applicability of these standards in the future.

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Supplemental Disclosure About Oil and Gas Producing Activities (Unaudited)
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The following oil and gas information is provided in accordance with the U.S. Financial Accounting Standards Board Statement No. 69 Disclosure About Oil and Gas Producing Activities . The Trust follows the full cost method of accounting.

(a) Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization at December 31, 2004, 2003 and 2002 as follows:

	2004	2003	2002
Capitalized costs of:			
Proved properties being amortized	**$ 181,778**	$ 112,220	$ 80,138
Undeveloped land not being amortized	**3,430**	5,037	3,967
Total capitalized costs	**185,208**	117,257	84,105
Less accumulated depletion, depreciation, future site restoration and amortization	**(67,268)**	(32,969)	(15,797)
Net Capitalized costs	**$ 117,940**	$ 84,288	$ 68,308

The following costs were incurred in oil and gas-producing activities during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
Property acquisition costs: [(1)]			
Proved properties	**$ 45,265**	$	$ 512
Unproved properties	**8,062**	8,028	3,643
Exploration costs	**4,289**	766	168
Development costs	**8,800**	42,503	31,558
Total costs incurred	**$ 66,416**	$ 51,297	$ 35,881

(1) Includes costs related to corporate acquisitions.

(b) Reserve Quantity Information

Estimated net quantities of proved gas and oil (including condensate) reserves at December 31, 2004, 2003 and 2002, and changes in the reserves during those years, are shown in the following two tables. Reserve volumes are reported on both net and gross of royalties basis.

	2004 Net	2003 Net	2002 Net	**2004 Gross**	2003 Gross	2002 Gross
Proved developed and undeveloped reserves Oil (mboe)						
At January 1	**4,457**	4,193	3,472	**5,149**	5,234	4,127
Changes in reserves:						
Extensions, discoveries and other additions	**139**	1,962	2,054	**158**	2,267	2,564
Revisions of previous estimates	**(96)**	(214)	(195)	**65**	(458)	(61)
Production	**(1,672)**	(1,062)	(446)	**(2,161)**	(1,406)	(533)
Purchases of oil in place	**2,363**	98		**2,684**	113	
Sales of oil in place	**(21)**	(520)	(692)	**(24)**	(601)	(863)
At December 31	**5,170**	4,457	4,193	**5,871**	5,149	5,234
Proved developed reserves Oil						
At January 1	**4,457**	3,239	3,131	**5,149**	3,952	3,734
At December 31	**5,069**	4,457	3,239	**5,755**	5,149	3,952

	2004 Net	2003 Net	2002 Net	**2004 Gross**	2003 Gross	2002 Gross
Proved developed and undeveloped reserves Gas (mboe)						
At January 1	**744**	1,706	1,342	**1018**	2,174	1,794
Changes in reserves:						
Extensions, discoveries and other additions	**25**	462	752	**28**	534	939
Revisions of previous estimates	**(167)**	(167)	(70)	**(124)**	(183)	(176)
Production	**(322)**	(322)	(263)	**(416)**	(427)	(314)
Purchases of gas in place	**637**	23		**723**	26	
Sales of gas in place		(958)	(55)		(1,106)	(69)
At December 31	**917**	744	1,706	**1,229**	1,018	2,174
Proved developed reserves Gas						
At January 1	**744**	1,606	1,233	**1,018**	2,038	1,650
At December 31	**909**	744	1,606	**1,219**	1,018	2,038

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(c) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein
The following tabulation has been prepared in accordance with the FASB s rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities owned by the Trust.

	2004	2003	2002
Future cash inflows [1]	**$ 260,750**	$ 207,948	$ 309,953
Less:			
Future development costs	**(677)**	(200)	(7,487)
Future production, royalty and abandonment costs	**(145,563)**	(83,332)	(109,383)
Future income tax expense	**(18,272)**	(15,174)	(54,959)
Future cash flows	**96,238**	109,242	138,124
Less annual discount (10% a year)	**(15,118)**	(18,683)	(31,453)
Standardized measure of discounted future net cash flows	**$ 81,120**	$ 90,559	$ 106,671

[1] Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year end.
In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pretax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB s standardized measure of discounted future net cash flows represent the fair market value of the Trust s proved reserves. The Trust cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules that are inherently imprecise and subject to revision, and the 10 percent discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

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The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year.

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Date: July 14, 2005

Enterra Energy Trust

/s/ E. Keith Conrad
E. Keith Conrad
President and Chief Executive Officer
(Duly Authorized Signing Officer)

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EXHIBIT INDEX

Number	Exhibit
2.1	Amalgamation Agreement dated May 27, 1998 between Temba Resources Ltd. and PTR Resources Ltd. pursuant to which the Registrant was amalgamated under the Business Corporations Act (Alberta) on June 30, 1998.[1]
2.2	Letter Agreement dated August 12, 1999 pursuant to which the Registrant acquired all of the issued and outstanding shares of 759795 Alberta Ltd.[2]
2.3	Notice of Intention to File a Normal Course Issuer Bid.[3]
3.1	Certificate of Amalgamation and attached Articles of Amalgamation of the Registrant dated and filed June 30, 1998.[4]
3.2	By-laws of the Registrant.[5]
3.3	Enterra Energy Trust Amended And Restated Trust Indenture.[6]
4.1	Amendment Agreement to the Trust Unit Purchase Agreement.[7]
4.2	Form of Warrant Agreement between the Registrant and the Representatives providing for the issuance of the Underwriters Warrants.[8]
4.3	Credit Facility Letter Agreement between the Alberta Treasury Branches and the Registrant as Borrower dated April 19, 2000.[9]
4.4	Promissory Notes dated June 5, 2000 granted by Westlinks to each of Glenn Russell, Patrick Williams Advisors, William J. Gordica, F. Jack Wright, Lawrence W. Underwood and Sapphire Capital Inc.[10]
4.5	Purchase and Sale Agreement dated April 6, 2000 between Sabre Exploration Ltd. and the Registrant.[11]
4.6	Consulting Agreement dated October 13, 2000 between Westlinks Resources Ltd. and Wells Gray Resort & Resources Ltd.[12]
4.7	Arrangement Agreement among Westlinks Resources Ltd. and 3779041Canada Ltd. and Big Horn Resources Ltd.[13]
4.8	Note Indenture.
4.10	Administration Agreement.
4.13	Second Amended and Restated Agreement of Business Principles.
4.14	Technical Services Agreement.
4.15	Arrangement Agreement.
4.16	Trust Unit Purchase Agreement.
12.1	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
12.2	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
13.1	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act
13.2	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act
99.1	Consent from KPMG LLP

99.2	Consent from Deloitte & Touche LLP
99.3	Consent from McDaniel & Associates Consultants Ltd.

[1] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.1, filed with the SEC 2000-06-21 (No. 333-39826).

[2] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.2, filed with the SEC 2000-06-21 (No. 333-39826).

[3] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 2.3, filed with the SEC 2000-06-21 (No. 333-39826).

[4] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 3.1, filed with the SEC 2000-06-21 (No. 333-39826).

[5] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 3.2, filed with the SEC 2000-06-21 (No. 333-39826).

[6] Incorporated by reference to the Company s Registration Statement on Form 8-A12G/A, filed 2003-11-28 (No. 000-32115).

[7] Incorporated by reference to the Company s Form 6-K dated July 15, 2005.

[8] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.2, filed with the SEC 2000-06-21 (No. 333-39826).

[9] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.3, filed with the SEC 2000-06-21 (No. 333-39826).

[10] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.4, filed with the SEC 2000-06-21 (No. 333-39826).

[11] Incorporated by reference to the Company s Registration Statement on Form F-1, Exhibit 4.5, filed with the SEC 2000-06-21 (No. 333-39826).

[12] Incorporated by reference to the Company s Registration Statement on Form F-1/A, Exhibit 4.6, filed with the SEC 2000-12-01 (No. 333-39826)

[13] Incorporated by reference to the Company s Annual Report on Form 20-F, Exhibit 1, filed with the SEC on 2001-06-18 (No. 000-32115).