ENTERRA ENERGY TRUST
Form 20-F
November 08, 2005

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

Amendment No. 1 to:
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 __________

o **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
Date of event reporting this shell company report
If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Acts. Yes o No o

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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This Amendment to the Form 20-F is being filed to remove references to the non-GAAP measure cash flow from operations and per unit measures of cash flow. We have replaced this disclosure with discussions of the GAAP measure cash provided by operating activities . With respect to our financial statements, we have revised the operating section of the Consolidated Statements of Cash Flows to remove the subtotal prior to change in non-cash working capital and accordingly, Note 17(k) to our consolidated financial statements has been removed. Further, the discussion of our oil and gas reserves has been modified to clarify that the disclosure in the Form 20-F is based on U.S., not Canadian, disclosure standards for oil and gas reserves.

On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts . In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling interest on the consolidated balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

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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(2)	Restated(1)(2)	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 and non-controlling interest		$ 14,415	$ 7,220	$ 5,878	$ 2,423	$ 3,880
Net earnings		$ 14,027	$ 5,430	$ 4,881	$ 1,700	$ 2,256
Basic earnings per unit/share		$ 0.62	$ 0.29	$ 0.27	$ 0.12	$ 0.26
Diluted earnings per unit/share		$ 0.62	$ 0.27	$ 0.26	$ 0.12	$ 0.25
Dividends paid on preferred shares	C$	$	$ 33	$ 23	$	$
Dividends paid on preferred shares	US$	$	$ 24	$ 15	$	$
Dividends paid on common shares		$	$	$	$	$
Weighted average units/shares outstanding basic		22,518	18,752	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		($ 7.62)	($ 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(2)	Restated(1)(2)	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	$ 148,458	$ 105,260	$ 96,142	$ 74,130	$ 19,588
Total assets	$ 221,128	$ 116,705	$ 104,505	$ 81,054	$ 23,354
Total Unitholders equity	$ 114,971	$ 44,545	$ 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) On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151

Exchangeable Securities Issued by Subsidiaries of Income Trusts . In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling interest on the consolidated balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

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

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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.

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 .

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 November 4, 2005, the noon buying rate was US$1.00 equals Cdn.$1.1815 and the inverse noon buying rate was Cdn.$1.00 equals US$08464.

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

	May 2005	June 2005	July 2005	August 2005	September 2005	October 2005
High	0.8086	0.8173	0.8317	0.8449	0.8630	0.8599
Low	0.7853	0.7943	0.8024	0.8168	0.8378	0.8387

B. Capitalization and Indebtedness

Not applicable

C. Reasons for the Offer and Use of Proceeds

Not applicable

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.

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;

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.

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 facilities 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 facilities consist of a revolving credit facility with a Canadian financial institution and bridge loan facility with a lending fund, both due November 30, 2005. Repayment of all outstanding amounts are due at that time. In order to pay out the existing facilities we need to obtain alternate financing. We anticipate entering into a new conventional revolving credit facility with a Canadian financial institution. 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 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.

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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 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. On September 8, 2005, the Department of Finance issued a paper and launched consultations on the economic and fiscal implications of flow-through entities (FTEs) including income trusts. Submissions will be received until December 31, 2005. On September 19, 2005 the Minister of Finance announced that he has asked the Minister of National Revenue to postpone providing advance rulings respecting FTEs. As of the date hereof, there has been no guidance issued by the

Department of Finance as to the nature of changes to the Tax Act, if any, that are being considered with respect to FTEs. Accordingly, as with all potential changes in law, no assurance can be given that changes will not be made to the Tax Act that adversely affect the Trust or holders of Trust Units.

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. On September 8, 2005, the Department of Finance issued a paper and launched 23 consultations on the economic and fiscal implications of flow-through entities (FTEs) including income trusts. Submissions will be received until December 31, 2005. On September 19, 2005 the Minister of Finance announced that he has asked the Minister of National Revenue to postpone providing advance rulings respecting FTEs. As of the date hereof, there has been no guidance issued by the Department of Finance as to the nature of changes to the Tax Act, if any, that are being considered with respect to FTEs. Accordingly, as with all potential changes in law, no assurance can be given that changes will not be made to the Tax Act that adversely affect the Trust or holders of Trust Units.

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.

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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.

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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, Enterra 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 31, 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. On August 17, 2005, the acquisition closed for consideration of approximately $201.0 million, including $1.3 million of transaction cost. In addition the Trust assumed $75 million in debt. The consideration consisted of 7,490,898 trust units valued at $168.5 million and 1,407,177 exchangeable shares (exchangeable on a one-to-one basis into trust units) valued at $31.7 million.

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.

The amounts available under our existing credit facilities 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 facilities consist of a revolving credit facility with a Canadian financial institution and bridge loan facility with a lending fund, both due November 30, 2005. Repayment of all outstanding amounts are due at that time. In order to pay out the existing facilities we need to obtain alternate financing. We anticipate entering into a new conventional revolving credit facility with a Canadian financial institution. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to Unitholders may be materially reduced.

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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
July, 2005	$ 0.16
August, 2005	$ 0.16
September, 2005	$ 0.17
October, 2005	$ 0.17

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 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 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.

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. However, the availability of cash 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 sufficient cash will be available for distribution to Unitholders in the amounts anticipated or at all. See *Risk Factors* .

We make monthly cash distributions to Unitholders. Our primary sources of cash are 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 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

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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 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

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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

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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.

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

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.

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 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:

Wells drilled	2004 Gross (Net)	2003 Gross (Net)	2002 Gross (Net)	2001 Gross (Net)	2000 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:

Wells drilled	Q1 2005 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** Restated[1]	**Q4 2003** Restated[1]	*Change*	**Year 2004** Restated[1]	**Year 2003** Restated[1]	*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 provided (used) by operating activities [2]	$ 14,192	$ (966)	1,569%	$ 42,345	$ 20,971	102%
Net earnings (loss)	$ 3,256	$ (4,754)	168%	$ 14,027	$ 5,430	158%
Net earnings (loss) per unit	$ 0.13	$ (0.25)	152%	$ 0.62	$ 0.29	114%
Average number of units outstanding	25,277	18,956	33%	22,518	18,787	20%
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) On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts . In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling interest on the consolidated balance sheets. Additionally pursuant to this

new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

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**
		Restated[1]		Restated[1]		
Revenue	$	108,293	$	72,097	$	25,746
Cash provided by operating activities [2]	$	42,345	$	20,971	$	22,474
Net earnings	$	14,027	$	5,430	$	4,881
Net earnings per unit basic	$	0.62	$	0.29	$	0.27
Net earnings per unit diluted	$	0.62	$	0.27	$	0.26
Average number of units outstanding		22,518		18,752		18,309
Total assets	$	221,128	$	116,705	$	104,505
Total bank debt and obligations under capital leases	$	47,315	$	38,129	$	29,358
Distribution per unit	US$	1.42	US$	0.10		N/A

(1) On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts . In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling interest on the consolidated balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by

subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

(2) The Trust had previously reported the Non-GAAP measure cash flow from operations , rather than the GAAP-based measure of cash provided by operating activities .

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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	$ 12,763	84%
As a percentage of production revenue	24%	19%	25%	22%	18%	22%

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%	-4%	23%	24%	-4%
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%	$ 47,315	$ 38,129	24%
Interest expense	$ 491	$ 410	20%	$ 2,222	$ 1,749	27%
As a percentage of production revenue	2%	3%	33%	2%	2%	0%
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 54% in 2004 and by 90% 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 Restated(1)	**Q4 2003** Restated(1)	*Change*	**Year 2004** Restated(1)	**Year 2003** Restated(1)	*Change*
Depletion and depreciation expense	$ 11,794	$ 6,210	90%	$ 35,976	$ 23,306	54%
As a percentage of production revenue	35%	40%	-13%	33%	33%	0%
Depletion and depreciation expense per boe	$ 16.18	$ 12.97	25%	$ 14.13	$ 12.71	11%

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subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

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 Restated[(1)]	Q4 2003 Restated[(1)]	*Change*	Year 2004 Restated[(1)]	Year 2003 Restated[(1)]	*Change*
Earnings (loss) before income taxes and non-controlling interest	**$ 3,103**	**$ (4,710)**	**166%**	**$ 14,415**	**$ 7,220**	**100%**
Add (deduct) income taxes	226	$ (377)	160%	$ 20	$ (2,122)	-100%
Add (deduct) non-controlling interest	**(73)**	**332**	-121%	(408)	332	-223%
Net earnings (loss)	**$ 3,256**	**$ (4,755)**	**168%**	**$ 14,027**	**$ 5,430**	**158%**
Net Earnings (loss) as a percentage of revenue	10%	30%	133%	13%	8%	63%
Net Earnings (loss) on a per boe basis	$ 4.47	$ (9.92)	147%	$ 5.04	$ 2.95	71%
Per unit information						
Net earnings (loss) per unit	$ 0.13	$ (0.25)	152%	$ 0.62	$ 0.29	137%
Average number of units outstanding	25,277	18,956	33%	22,518	18,752	20%

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balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

Cash Provided By Operating Activities

Cash provided (used) by operating activities grew in 2004 as compared with 2003. On an annual basis cash provided by operating activities was $42.3 million in 2004, an increase of $21.4 million from 2003. The increased cash from operating activities in 2004 as compared with 2003 was the result of a $8.6 million increase in net earnings adjusted by $12.8 million for non-cash items included in net earnings and changes in non-cash net working capital. Cash provided by operating activities was $14.2 million in Q4 2004, an increase of $15.2 million from Q4 2003. The increased cash from operating activities in Q4 2004 as compared with Q4 2003 was the result of a $8.5 million increase in net earnings adjusted for $6.7 million of non-cash items included in net earnings and changes in non-cash net working capital.

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CASH PROVIDED BY OPERATING ACTIVITIES ***(in Thousands except for per unit amounts)***

	Q4 2004 Restated[1]	**Q4 2003** Restated[1]	***Change***	**Year 2004** Restated[1]	**Year 2003** Restated[1]	***Change***
Net earnings (loss)	**$ 3,256**	**$ (4,755)**	**168%**	**$ 14,027**	**$ 5,430**	**158%**
Add back depletion and depreciation	11,794	6,210	90%	35,976	23,306	54%
Add back (deduct) amortization of deferred financing charges	(18)	(27)	33%	33	262	-87%
Add (deduct) Non controlling interest	73	(332)	(122)	408	(332)	-223%
Add back (deduct) future income taxes	(396)	331	-203%	(280)	1,988	-114%
Deduct amortization of deferred gain		(1)			(238)	-100%
Asset Retirement Expenditures		(5)			(5)	%
Add back (deduct) non-cash expense related to warrants/ options	(606)	282	-315%	78	282	-72%
Change in accounts receivable	(2,137)	(146)	-1,364%	(4,393)	(1,429)	-207%
Change in prepaid expenses	(134)	23	-683%	(57)	195	-129%
Change in accounts payable and accrued liabilities	2,190	(2,431)	190%	(3,607)	(8,453)	57%
Change of income taxes payable	170	(115)	248%	160	(35)	557%
Cash provided by operating activities	**$ 14,192**	**$ (966)**	**1,569%**	**$ 42,345**	**$ 20,971**	**102%**
Cash provided by operating activities as a percentage of revenue	42%	-6%	800%	39%	29%	34%

(1) On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts .

In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling interest on the consolidated balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.

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.

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.

Change in Accounting Policy

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(a) Non-controlling interest (NCI)

On January 19, 2005, the CICA issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts that states that 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 to be classified as equity. The Trust s exchangeable shares are transferable and, in accordance with EIC-151, have been reclassified to non-controlling interest on the consolidated balance sheets.

Since the Enterra exchangeable shares (note 10 to the amended consolidated financial statements) were not initially recorded at fair value, subsequent exchanges for Trust Units are measured at the fair value of the Trust Units issued. The amounts in excess of the carrying value of exchangeable shares are allocated to property, plant and equipment, to the extent possible, with any excess amounts being allocated to goodwill. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings.

Prior to the adoption of EIC 151, Trust Units that would be issued upon conversion of exchangeable shares were included in the calculation of basic earnings per unit. As a result of the new standard exchangeable shares are excluded from the calculation of basic earnings per unit but are reflected in the calculation of diluted earnings per unit. Prior periods have been retroactively restated as required by the new accounting standard.

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The following tables illustrate the impact of the new accounting policy for periods which have been presented for comparative purposes

Balance Sheet as at December 31, 2004	Balance as reported prior to NCI restatement	Adjustments for NCI	Balance as restated
Property, plant and equipment	$ 146,910	$ 1,548	$ 148,458
Goodwill	29,991	19,279	49,270
Future income tax liability	21,526	602	22,128
Non-controlling interest		3,349	3,349
Unitholders capital	111,653	20,554	132,207
Exchangeable shares	3,276	(3,276)	
Accumulated earnings	27,903	(405)	27,498
Basic weighted average number of units outstanding	23,327,728	(809,355)	22,518,373
Diluted weighted average number of units outstanding	23,560,785	(318,825)	23,241,960

Balance Sheet as at December 31, 2003	Balance as reported prior to NCI restatement	Adjustments for NCI	Balance as restated
Property, plant and equipment	$ 105,253	$ 7	$ 105,260
Goodwill		37	37
Future income tax liability	13,936	3	13,939
Non-controlling interest		3,125	3,125
Unitholders capital	32,838	41	32,879
Exchangeable shares	3,457	(3,457)	
Accumulated earnings	13,785	332	14,117
Basic weighted average number of units outstanding	18,953,968	(202,334)	18,751,634
Diluted weighted average number of units outstanding	18,953,968	(40)	18,953,928

Statement of Earnings for the year ended December 31, 2004	Balance as reported prior to NCI restatement	Adjustments for NCI	Balance as restated
Depletion, depreciation and accretion	$ 35,438	$ 538	$ 35,976
Future income tax recovery	(71)	(209)	(280)
Net earnings before non-controlling interest	14,764	(329)	14,435
Non-controlling interest		408	408
Net earnings	14,764	(737)	14,027
Net earnings per unit basic	$ 0.63	($ 0.01)	$ 0.62

Net earnings per unit diluted	$	0.63	($	0.01)	$	0.62

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Statement of Earnings for the year ended December 31, 2003	Balance as reported prior to NCI restatement	Adjustments for NCI for NCI	Balance as restated
Non-controlling interest	$	($ 332)	($ 332)
Net earnings	5.098	(332)	5,430
Net earnings per unit basic	$ 0.27	$ 0.02	$ 0.29
Net earnings per unit diluted	$ 0.27	$ 0.00	$ 0.27

The retroactive implementation of EIC 151 had no impact on the statement of earnings for the year ended December 31, 2002**.**

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 June 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. 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 provided by operating activities	$ 20,971	$ 22,474	- 7%
Average number of units outstanding *(after giving effect to trust conversion)*	18,752	18,309	+ 2%
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%

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

	2003 Restated[2]	2002
Revenue	$ 72,097	$ 25,746
Net earnings	$ 5,430	$ 4,881
Net earnings per unit basic	$ 0.29	$ 0.27
Net earnings per unit diluted	$ 0.27	$ 0.26
Average number of units outstanding *(after giving effect to trust conversion)*	18,752	18,309
Total assets	$ 116,705	$ 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.*

[2] *On January 19, 2005, the Canadian Institute of Chartered Accountants issued EIC-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts . In accordance with this new Canadian GAAP standard the Trust s exchangeable shares have been retroactively reclassified to non-controlling*

interest on the consolidated balance sheets. Additionally pursuant to this new standard, as certain exchangeable shares were issued by subsidiaries of the Trust and initially recorded at book value all subsequent exchanges of these exchangeable shares for trust units must be measured at the fair value of the trust units issued. The excess amounts of the book value over fair market value are allocated to property, plant and equipment, goodwill and future income tax. In addition, a portion of consolidated earnings before non-controlling interest is reflected as a reduction to such earnings in the Trust s consolidated statements of earnings and accumulated earnings. Prior periods have been *retroactively restated. The retroactive restatements were required by the transitional provisions of the new accounting standard.*

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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	$ 12,763	$ 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		