ENTERRA ENERGY TRUST
Form 20-F
June 26, 2009

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934.

OR

R ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the fiscal year ended December 31, 2008.

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934.

OR

SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
Date of event requiring this shell company report ……………….

For the transition period from ____________________ to _____________________

Commission file number 000-32115

ENTERRA ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Alberta, Canada

(Jurisdiction of Incorporation or Organization)

Suite 2700, 500 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6
(Address of Principal Executive Offices)

Blaine Boerchers, Suite 2700, 500 – 4th Avenue S.W., Calgary, Alberta, Canada, T2P 2V6,
Tel: (403) 538-3580, Fax: (403) 294-1197
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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
Trust Units	New York Stock Exchange

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

Trust Units

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

(Title of Class)

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, 2008: 62,158,987

Indicate by check mark whether if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934.
Yes No R

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.
Yes No R

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether if 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 R No

Indicate by check mark whether if the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer
Non-Accelerated filer R

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP International Financial Reporting Standards as issued by the International Accounting Standards Board Other R

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.
Item 17 R Item 18

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 Act.
Yes No R

(APPLICABLE ONLY TO ISSUER INVOLVED IN BANKRUPTCY PROCEEDINGS DURING THE PAST FIVE YEARS)

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court
Yes No R

Note Regarding Forward-Looking Statements

Certain information contained herein may contain forward-looking statements including management's assessment of future plans and operations, drilling plans and timing thereof, expected production increases from certain projects and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding wells to be drilled, expected or anticipated production rates, expected exchange rates, distributions and method of funding thereof, proportion of distributions anticipated to be taxable and non-taxable, anticipated borrowing base under credit facility, maintenance of productive capacity and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks. All statements other than statements of historical facts contained in this MD&A are forward-looking statements. The words "believe", "may", "will", "estimate", "continue", "anticipate," "intend", "should", "p and similar expressions, as they relate to the Trust, are intended to identify forward-looking statements. The Trust has based these forward-looking statements on the current expectations and projections about future events and financial trends that the Trust believes may affect its financial condition, results of operations, business strategy and financial needs.

These forward-looking statements are subject to uncertainties, assumptions and a number of risks, including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The recovery and reserve estimates of Enterra's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Trust. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Trust operates; the timely receipt of any required regulatory approvals; the ability of the Trust to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Trust has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Trust to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisitions, development and exploration; the timing and cost of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate reasonably priced transportation; future commodity oil and gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Trust operates; and the ability of the Trust to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Additional information on these and other factors could effect Enterra's operations and financial results are included in reports on file with the Canadian and United States regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or the EDGAR website (www.sec.gov/edgar.shtml), or at Enterra's website (www.enterraenergy.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Enterra does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of the new information, future events or otherwise, except as may be required by applicable securities law. Other sections of this MD&A may include additional factors that could adversely affect the business and financial performance. The Trust operates in a very competitive and rapidly changing business environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, nor can the Trust assess the impact of all factors on its 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. The reader should not rely upon forward-looking statements as predictions of future events or performance. The Trust cannot provide assurance that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although the Trust believes that the expectations reflected in the forward-looking statements are reasonable, the Trust cannot guarantee future results, levels of activity, performance or achievements.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes.

Glossary

The following are defined terms used in this form 20-F:

"ABCA" means the Business Corporations Act (Alberta);

"Administration Agreement" means an administration agreement dated November 25, 2003 between the Trust and EEC;

"CT Notes" means the unsecured promissory notes issued by EECT to the Trust;

"Debentures" means the 8% and/or the 8.25% convertible unsecured subordinated debentures of the Trust issued under the Debenture Indenture;

"Delaware GCL" means Delaware General Corporation Law;

"EAC" means Enterra Acquisitions Corp., a corporation incorporated under the Delaware GCL and an indirect subsidiary of the Trust;

"EEC" means Enterra Energy Corp., a corporation incorporated under the ABCA, a wholly-owned subsidiary of the Trust, and administrator of the Trust pursuant to the Administration Agreement;

"EEC Exchangeable Shares" means shares of EEC that were exchangeable for Trust Units;

"EECT" means Enterra Energy Commercial Trust, an unincorporated trust governed by the laws of Alberta and a wholly owned subsidiary of the Trust;

"EECT Units" means trust units of EECT;

"EEPC" means Enterra Energy Partner Corp., a corporation incorporated under the ABCA. EEPC is a holding company wholly owned by EEC which holds an interest in EPP;

"Enterra Arrangement" means the plan of arrangement completed on November 25, 2003 involving the Trust, EECT, Old Enterra and its subsidiaries, and Enterra Acquisition Corp.;

"Enterra US Acqco" means Enterra US Acquisitions Inc., a corporation incorporated under the Delaware GCL and an indirect subsidiary of the Trust;

"EPC" means Enterra Production Corp., a corporation incorporated under the ABCA and was a wholly-owned subsidiary of the Trust prior to January 31, 2007;

"EPP" means the Enterra Production Partnership, a partnership organized pursuant to the laws of Alberta;

"Exchangeco" means Enterra Exchangeco Ltd., a corporation incorporated under the ABCA and a wholly-owned subsidiary of EECT;
"GAAP" means generally accepted accounting and principles in Canada;

"Haas" means Haas Petroleum Engineering Services, Inc., independent petroleum engineering consultants;

“Haas Report” means the independent engineering evaluation of certain oil, NGL and natural gas interests of the Trust prepared by Haas dated March 5, 2009 and effective January 1, 2009;

“High Point” means High Point Resources Inc., a corporation incorporated under the ABCA;

“JED” means JED Oil Inc., a corporation incorporated under the ABCA;

“JED Swap” means the exchange, completed on September 28, 2006 with an effective date of July 1, 2006, of the Trust’s interests in certain properties for interests held by JED and the settlement of certain indebtedness owed to JED;

“JMG” means JMG Exploration, Inc., a Nevada corporation;

“US Farmout Partner” means Petroflow Energy Ltd.;

"McDaniel" means McDaniel & Associates Consultants Ltd., independent petroleum engineering consultants;

"McDaniel Report" means the independent engineering evaluation of certain oil, NGL and natural gas interests of the Trust prepared by McDaniel dated February 17, 2009 and effective December 31, 2008;

"Non-Resident" means (a) a person who is not a resident of Canada for the purposes of the Tax Act and any applicable income tax convention; or (b) a partnership that is not a Canadian partnership for the purposes of the Tax Act;

"Old Enterra" means EEC prior to the Enterra Arrangement;

"Operating Subsidiaries" means collectively, the direct and indirect subsidiaries of the Trust that own and operate assets for the benefit of the Trust (with the material Operating Subsidiaries being EEC, EPP, EAC, and Enterra US Acqco);

"Reserve Reports" means, collectively, the McDaniel Report and Haas Report;

"Revolving and Operating Credit Facilities" means
(i) a revolving credit facility with a syndicate of lenders, and
(ii) ans operating facility with Bank of Nova Scotia as lender,
provided pursuant to the second amended and restated syndicated credit agreement dated June 25, 2008;

"RMAC Exchangeable Shares" means shares of RMAC that were exchangeable for Trust Units;

"RMEC" means Rocky Mountain Energy Corp., a corporation created by amalgamation under the laws of Alberta;

"RMG Exchangeable Shares" means exchangeable shares issued by Enterra US Acqco that were exchangeable for Trust Units;

"Second-Lien Credit Facility" means a second-lien non-revolving credit facility with a syndicate of lenders provided pursuant to a credit agreement dated June 25, 2008;

"Series Notes" means interest bearing subordinated promissory notes issued by certain Operating Subsidiaries and currently held by the Trust;

"Special Resolution" means a resolution passed as a special resolution at a meeting of holders of Trust Units and holders of Special Voting Rights (including an adjourned meeting) duly convened for the purpose and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units and Special Voting Rights represented at the meeting;

"Special Voting Right" means the special voting right of the Trust issued by the Trust to and deposited with the Trustee, which entitled the holders of the exchangeable shares to a number of votes at meetings of the Unitholders;

"Tax Act" means the Income Tax Act (Canada) and the Regulations thereunder, as amended from time to time;

"Technical Services Agreement" means the Technical Services Agreement between the Trust and JED dated effective January 1, 2004 and terminated on January 1, 2006;

"Trust" means Enterra Energy Trust, an unincorporated trust governed by the laws of Alberta, and where the context requires, includes the Trust and all of the Trust Subsidiaries as a consolidated entity;

"Trust Indenture" means the amended and restated trust indenture dated November 25, 2003 among Olympia Trust Company, as trustee, Luc Chartrand as settler, and EEC, as may be amended, supplemented, and restated from time to time;

"Trust Subsidiaries" means the Operating Subsidiaries, EECT, and any other subsidiaries of the Trust;

"Trust Units" mean units of the Trust;

"Trustee" means the trustee of the Trust, presently Olympia Trust Company;

"Unitholders" mean holders from time to time of the Trust Units;

"U.S. Person" means a U.S. person as defined in Rule 902(k) under Regulation S, including, but not limited to, any natural person resident in the United States; and

"U.S. Unitholder" means any Unitholder who is either in the United States or a U.S. Person.

Abbreviations, Conventions and Conversions

Abbreviations

AECO	Intra Alberta Nova Inventory Transfer Price (NIT net price)	Mboe	thousands of barrels of oil equivalent
API	American Petroleum Institute	mcf	thousand cubic feet of natural gas
°API"	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28°API or higher is generally referred to as light crude oil	mcf/d	thousand cubic feet of natural gas per day
ARTC	Alberta Royalty Tax Credit	Mmcf/d	million cubic feet of natural gas per day
bbl or bbls	barrels of oil	Mmcf	million cubic feet of natural gas
bbls per day or bbl/d	barrels of oil per day	mcf per day	thousands of cubic feet of natural gas per day
Bcf	Billion cubic feet of natural gas	mmbtu	millions of British Thermal Units
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)	Mmbtu per day	millions of British Thermal Units per day
boe per day or boe/d	barrels of oil equivalent per day	Mwh	Megawatt hours
Cdn$	Canadian dollars	NGL or NGLs	natural gas liquids (ethane, propane, butane and condensate)
FD&A	Finding Development & Acquisition Costs	NI 51-101	National Instrument 51-101
FDC	Future Development Costs	NYMEX	New York Mercantile Exchange
GAAP	Canadian Generally Accepted Accounting Principles	Q1	first quarter of the year - January 1 to March 31
GJ	Gigajoule	Q2	second quarter of the year - April 1 to June 30
GJ/d	gigajoule per day	Q3	third quarter of the year - July 1 to September 30
GORR	Gross overriding royalty	Q4	fourth quarter of the year - October 1 to December 31
LNG	Liquefied Natural Gas	US$	United States dollars
m3	cubic metres	WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
mbbl	thousand barrels of oil		

Conventions

Unless otherwise indicated, all dollar amounts are in Canadian dollars and references herein to “$” or “dollars” are to Canadian dollars or “M$” are to a thousand Canadian dollars or “MM$” are to a million Canadian dollars.

The information set out in this 20-F is stated as at December 31, 2008 unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

Conversions

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units):

To Convert from	To	Multiply by
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.4047
Hectares	Acres	2.471

PART 1

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, 2008, 2007, 2006, 2005, and 2004 and for each of the years in the five year period ended December 31, 2008 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, 2008, 2007, 2006, 2005 and 2004. 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.

For the years ended December 31 (in thousands of Canadian dollars except for per unit amounts)	2008	2007	2006	2005	2004
Amounts in Accordance with Canadian GAAP					
FINANCIAL					
Revenue before mark-to-market adjustment (1)	255,268	223,828	233,592	157,743	108,293
Income (loss) before taxes	11,892	(177,986)	(121,850)	(16,292)	14,953
Per unit ($)	0.19	(2.98)	(2.76)	(0.55)	0.64
Net income (loss)	7,061	(142,036)	(64,239)	970	14,764
Per unit ($)	0.11	(2.38)	(1.46)	0.03	0.62
Per unit – diluted ($)	0.11	(2.38)	(1.46)	0.03	0.62
Total assets	587,018	599,790	795,366	611,543	200,301
Net assets	294,416	219,184	403,756	322,111	98,095
Unitholders' equity	294,416	219,184	402,024	289,707	98,095
SHARES AND UNITS OUTSTANDING					
Weighted average units outstanding (000s)	61,661	59,766	44,142	29,534	23,328
Units outstanding at period end (000s)	62,159	61,436	56,098	36,504	25,427

Amounts in Accordance with U.S. GAAP (2)

FINANCIAL					
Revenue before mark-to-market adjustment (1)	255,268	223,828	233,592	157,743	108,293
Income (loss) before taxes	(46,687)	(47,747)	76,787	(28,989)	7,536
Per unit ($)	(0.76)	(0.80)	1.71	(0.94)	0.32
Net income (loss)	(31,802)	(65,664)	(280,348)	(18,780)	10,338
Per unit ($)	(0.52)	(1.10)	(6.26)	(0.61)	0.44
Per unit – diluted ($)	(0.52)	(1.10)	(6.26)	(0.61)	0.44
Total assets	279,389	387,045	465,676	530,433	171,331
Net assets	2,995	22,247	115,026	262,821	80,037
Unitholders' equity, including mezzanine equity	2,995	22,247	115,026	262,821	80,037
SHARES AND UNITS OUTSTANDING					
Weighted average units outstanding (000s)	61,661	59,766	44,846	30,834	23,328
Units outstanding at period end (000s)	62,159	61,436	56,098	36,504	25,427

(1) Revenue before mark-to-market adjustment is a non-GAAP measure. Refer to the "Revenues" section in Item 5.A.
(2) See note 21 to the consolidated financial statements for an explanation of the significant differences between Canadian and U.S. GAAP.

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 wire transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York. The exchange rates are presented as U.S. dollars per Canadian dollar. On June 22, 2009, the noon buying rate was US$1.00 equals Cdn$1.1547 and the inverse noon buying rate was Cdn$1.00 equals US$0.8660.

U.S. Dollar per Canadian Dollar

	High	Low
May 2009	0.9198	0.8423
April 2009	0.8375	0.7910
March 2009	0.8167	0.7692
February 2009	0.8202	0.7758
January 2009	0.8458	0.7849
December 2008	0.8358	0.7711

Year Ended December 31
U.S. Dollar per Canadian Dollar

	2008	2007	2006	2005	2004
Average	0.9381	0.9304	0.8818	0.8253	0.7683

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Volatility in oil and natural gas prices could have a material adverse effect on results of operations and financial condition, which, in turn, could affect the market price of the Trust Units or Debentures and the amount of distributions to Unitholders.

The Trust's business, results of operations, financial condition and future growth are substantially dependent on the prevailing prices for its production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes in supply or demand, whether the result of uncertainty or a variety of additional factors beyond the Trust's control including, without limitation, actions taken by OPEC and its adherence to agreed production quotas, war, terrorism, government regulation, social and political conditions, economic conditions, prevailing weather patterns and the availability of alternative sources of energy. Any substantial decline in the price of oil or natural gas could have a material adverse effect on the Trust's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the properties, planned level of spending for exploration, and development and level of reserves. No assurance can be given that prices for oil or natural gas will be sustained at levels that will enable the Trust to operate profitably or make distributions.

The Trust uses financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from decline in oil and natural gas prices. In addition, the commodity hedging activities could expose the Trust 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 the hedging policies and procedures are not followed. Furthermore, it is unlikely that such hedging transactions will fully offset the risks of changes in commodity prices.

The Revolving and Operating Credit Facilities may not provide sufficient liquidity.

The Trust's Revolving and Operating Credit Facilities may not provide the Trust with sufficient funding for future operations, or Enterra may not be able to obtain additional financing on attractive economic terms, if at all. On June 25, 2008 Enterra entered into credit facilities with its banking syndicate that includes revolving and operating credit facilities which has a current borrowing capacity of $110.0 million. The revolving and operating credit facilities are secured with a first priority charge over the assets of Enterra. Borrowings under the revolving and operating credit facilities at March 31, 2009 were $80.0 million. The maturity date of the revolving and operating credit facilities is June 25, 2010 and should the lenders decide not to renew the facility, the debt must be repaid on June 25, 2011.

The Trust's obligations to its lenders may have a material adverse affect on the ability to pay distributions to Unitholders.

The payment of interest and principal, and other costs, expenses and disbursements to the lenders reduces the amounts available for potential distribution to Unitholders. Variations in interest rates and required principal repayments could result in significant changes to the amount of the funds from operations required to be applied to the debt before payment of any amounts to Unitholders. The agreement governing the Revolving and Operating Credit Facilities provides that if the Trust is in default of its terms, or if amounts outstanding exceed the amount of the borrowing base, the ability to make distributions to Unitholders may be restricted. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

The Trust's assets are leveraged. Any material change in liquidity could impair its ability to make potential distributions to Unitholders and could adversely affect the market price of the Trust Units or Debentures.

The bank debt is secured by the Trust's assets. A decrease in the amount of production or the price received for it could make it difficult for the Trust to service the debt or may cause the lenders to determine that its assets are insufficient security for the debt. Repayment of all or a portion of outstanding amounts under the Revolving and Operating Credit Facilities may be demanded on relatively short notice. If this occurs, the Trust may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on the Trust's business, or adversely affect the market price of the Trust Units or Debentures. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

An inability to add additional reserves through development or acquisition could have a material adverse effect on the market price of the Trust Units or Debentures.

The Trust does not focus on the exploration for oil and natural gas reserves. Instead, the Trust adds to its oil and natural gas reserves primarily through development, exploitation and acquisitions. As a result, future oil and natural gas reserves are highly dependent on success in developing and exploiting existing properties and acquiring additional reserves. Accordingly, if external sources of capital, including the issuance of additional Trust Units or other securities, become limited or unavailable on commercially reasonable terms, the Trust's ability to make the necessary capital investments to maintain or expand oil and natural gas reserves will be impaired. To the extent that the Trust is required to use funds from operations to finance capital expenditures or property acquisitions, the level of funds from operations available for distribution to Unitholders will be reduced. Additionally, the Trust cannot guarantee that it will be successful in developing or exploiting additional reserves or acquiring additional reserves on terms that meet its investment objectives. Without these reserve additions, the Trust's reserves will deplete and as a consequence, either production from, or the average reserve life of, the properties will decline. Either decline may result in a reduction in the value of the Trust Units and in a reduction in cash available for potential distributions to Unitholders.

A decline in the Trust's ability to market its oil and natural gas production could have a material adverse effect on production levels or on the price received for production, which, in turn, could have a material adverse effect on the market price of the Trust Units or Debentures.

The Trust's business depends in part upon the availability, proximity and capacity of oil and 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 the Trust's ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of the Trust's production, overall production or realized prices may decline, which could reduce potential distributions to Unitholders.

Fluctuations in foreign currency exchange rates could have a material adverse effect on the business.

The price that is received for a majority of the Trust's oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that is received 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. The Trust could be subject to unfavourable price changes to the extent that the Trust has engaged, or in the future engages, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Distributions, if any, may be reduced during periods in which capital expenditures are made or debt repaid using cash flow.

To the extent that the Trust uses cash flow to finance acquisitions, development costs and other significant expenditures, the portion of funds from operations that is available for distribution to Unitholders will be reduced. As a result, the timing and amount of capital expenditures may affect the amount of cash available to distribute to Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The Board of EEC, the administrator and principal operating subsidiary of the Trust, has the discretion to determine the extent to which funds from operations will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the Revolving and Operating Credit Facilities. As a consequence, the amount of funds EEC retains 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.

Actual reserves will vary from reserve estimates, and those variations could have a material adverse effect on the market price of the Trust Units or Debentures and distributions to Unitholders.

The reserve and recovery information contained in the Reserve Reports relating to the Trust's reserves are only estimates and the actual production and ultimate reserves from its properties may be greater or less than the estimates prepared by such firms.

The value of the Trust Units and Debentures depends upon, among other things, the reserves attributable to the Trust's properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to the 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.

As a portion of the Trust's production is from geological formations with relatively limited long term production history, actual results are more likely to vary from estimates.

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 the Trust's control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates.

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

As the Trust expands its operations beyond conventional oil and natural gas production in Western Canada, it may face new challenges and risks.

The Trust's operations and expertise were previously focused on the production of conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the first quarter of 2006, properties in Oklahoma were acquired. The Trust has gained significant experience operating in this jurisdiction but will still face operating and business challenges that it cannot foresee and therefore will need to rely on local management.
The Trust Indenture does not limit the Trusts activities to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of activities into new areas presents challenges and risks that the Trust may not have faced in the past. If the Trust does not manage these challenges and risks successfully, results of operations and financial condition could be adversely affected.

Incorrect assessments of value at the time of acquisitions could have a material adverse effect on the market price of the Trust Units or Debentures and distributions to Unitholders.

The price that the Trust is 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 that are acquired 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 the Trust's engineers, and these initial assessments may differ significantly from its subsequent assessments.

The Trust may undertake acquisitions that could limit its ability to manage and maintain the business, resulting in adverse accounting treatment or could be difficult to integrate into the business. Any of these events could result in a material change in the Trust's liquidity, impair its ability to make distributions to Unitholders and could adversely affect the market price of the Trust Units or Debentures.

A component of the future growth depends on the Trust's ability to identify, negotiate, and acquire additional entities and assets that complement or expand the existing operations. However the Trust may be unable to complete any acquisitions or any acquisitions that may be completed may not enhance the business. Any acquisitions could subject the Trust 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 the organization effectively.

The exploration, development and operation of a portion of the Trust's properties is dependent on third-parties, and their failure to perform or harm to their business could adversely affect the revenues and ultimately the distributions to Unitholders.

The exploration and development of a portion of the Trust's properties may be undertaken by industry partners and a lack of success or an inability to perform by such partners would affect the future prospects, revenues and distributions.

The Trust still has limited experience operating properties in the United States and therefore is reliant on the local employees and on the U.S. Farmout partner for technical and operational support. It is the Trust's expectation that it will gain more insight into the technical and operational characteristics of each of these properties through these relationships. Any early termination or deterioration of the relationship with a partner, or any inability to rapidly understand the geology and production characteristics of the properties, could have a material adverse effect on the market price of the Trust Units or Debentures.

On properties where the Trust is not the operator, it is reliant on the operator for continuing production from the property, and to some extent, the marketing of that production. During 2008, approximately 5% of 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, the Trust's revenue may be reduced. Third-party operators also make estimating future capital expenditures more difficult.

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

The exploration, development and exploitation of a portion of the Trust's properties is dependent on technological advancements becoming available on a timely basis. Any failure to obtain or delay in achieving the advancements could adversely affect the market price of the Trust Units or Debentures and distributions to Unitholders.

The exploration, development and exploitation of the Trust's properties and the ultimate amount of reserves recovered are dependant on being able to access technological advancements on a timely basis. If these technological advancements are not available it may not be possible to maximize the contribution to the market value of the Trust Units or Debentures. Delays in business operations could adversely affect the distributions to Unitholders.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the 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 the Trust to additional third party credit risks.

Changes in market-based factors may adversely affect the trading price of the Trust Units or Debentures.

The market price of the Trust Units is primarily a function of anticipated distributions to Unitholders and the value of the Trust's properties. The market price of the Trust Units or Debentures is therefore sensitive to a variety of market-based factors, including, but not limited to, interest rates and the comparability of the Trust Units or Debentures to other similar securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units or Debentures.

The Trust's operations are entirely dependent on the Trust's management and the loss of key management and other personnel could negatively impact the business.

Unitholders are entirely dependent on the Trust's management 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 the 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 us.

Management of the Trust may have conflicts of interest.

There are conflicts of interest to which several of the directors and officers are subject in connection with the Trust's operations. In particular, certain of the directors and officers are involved in managerial or directorial positions with other oil and gas companies whose operations, from time to time, are in direct competition with the Trust's operations. Additionally, certain of the directors and officers may become involved with entities which may, from time to time, provide financing to, or make equity investments in, the Trust's competitors. See "Conflicts of Interest and Interests of Management and Others in Material Transactions".

The Trust may be unable to successfully compete for resources with other organizations in the industry.

The Trust competes for capital, reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Trust. 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 the competitors may have greater and more diverse competitive resources to draw on than the Trust. In addition, to the extent Enterra's Trust Units receive a lower market valuation relative to competing entities, there will be a disadvantage in acquiring properties in competition with such entities. Given the highly competitive nature of the oil and natural gas industry, any competitive disadvantage could adversely affect the market price of the Trust Units or Debentures and distributions to Unitholders.

The industry in which the Trust operates exposes it to potential liabilities that may not be covered by insurance.

The Trust's 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, 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 the property or the property of others. The Trust cannot fully protect against all of these risks, nor are all of these risks insurable. The Trust may become liable for damages arising from these events against which it cannot insure or against which it 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 Trust may incur material costs and liabilities to comply with or as a result of health, safety and environmental laws and regulations.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, state, provincial and federal legislation in Canada and the United States. A breach of that legislation may result in the imposition of administrative, civil or criminal penalties, damages, fines, the issuance of "clean up" orders or the issuance of injunctions limiting or prohibiting some or all of its operations. Strict liability may be incurred under these environmental regulations and legislation in connection with discharges or releases of petroleum hydrocarbons and wastes into the environment as a result of the operations. In addition, legislation regulating the oil and natural gas industry may be changed to impose higher standards and potentially more costly obligations. The 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol, was ratified by the Canadian government in December 2002 and would require, among other things, significant reductions in greenhouse gases. In 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only the oil and natural gas industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products. In 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "Updated Action Plan") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. Additionally in 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force (the "Canada-Alberta ecoEnergy Plan"), which recommends among other things: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and

(iii) targeting research to lower the cost of technology. In 2007,

The impacts from the Kyoto Protocol, the Action Plan, the Updated Action Plan and the Canada-Alberta ecoEnergy Plan on the Trust are uncertain and may result in significant additional costs for the Trust's operations. Although the Trust records a provision in the financial statements relating to estimated future environmental and reclamation obligations, it cannot guarantee that it will be able to satisfy the actual future environmental and reclamation obligations.

Enterra is 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, the Trust's 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 funds from operations and therefore, will reduce the amount of funds available for distribution to Unitholders. Should the Trust be unable to fully fund the cost of remediating an environmental problem, it might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Climate change impact

Enterra faces a variety of uncertainties related to climate change. The oil and gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation in Canada and federal and state laws and regulations in the United States. These range from potential impacts from emissions restrictions, carbon taxes and other government policy initiatives, to changes in weather patterns that may affect operations. Both the Alberta provincial government and the Canadian federal government have introduced planned legislative concepts that are intended, among other things, to drive industry towards CO_2 emissions reduction and CO_2 capture and sequestration in below ground geologic formations. In early 2008, the British Columbia provincial government announced its intention to introduce a carbon tax on fuels. Although Enterra is not a large emitter of greenhouse gases, these forms of legislation may have an impact on both revenues and cost structures at a future undetermined time.

Another potential climate change impact on the Trust may result from the direct consequences of weather events. These may range from extreme cold events, to early break up in winter-only areas and unusual storms.

Lower oil and gas prices increase the risk of impairment of the Trust’s oil and gas property investments.

All costs related to the exploration for and the development of the Trust’s oil and gas reserves are capitalized into one of two cost centers, Canada and the United States. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells and production equipment. General and administrative costs are capitalized if they are directly related to development or exploration projects. Proceeds from the disposal of oil and natural gas properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a 20% change in the depletion rate.

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. The amounts recorded for depletion, depreciation and the asset retirement obligation are based on these estimates. The carrying value of the Trust’s petroleum and natural gas properties, which may be depleted against revenues of future periods, is limited to the estimated fair value of these properties (the “ceiling test”). The ceiling test is conducted separately for each cost center. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value of the cost center. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of petroleum and natural gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. The ceiling test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs (including asset retirement costs) and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods. The risk that the Trust 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.

While a write down does not directly affect funds from operations, the charge to earnings could be viewed unfavourably in the market or could limit the Trust's ability to borrow funds or comply with covenants contained in current or future credit agreements or other debt instruments.

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

Although the Trust conducts 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 the title to the purchased assets. If such a defect were to occur, the Trust's 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 the Trust of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of Western Canada. The Trust is unable to assess the effect, if any, that any such claim would have on the business and operations.

Electricity costs and water production may have an impact on operating costs.

The Trust's Oklahoma and Alberta properties consume significant quantities of electricity to drive motors and pumps for the production of hydrocarbons and the lifting and re-injection of formation water. The cost of electricity is a major component of lifting expense. While the Trust tries to purchases electrical power at competitive rates, it cannot guarantee that changes in market conditions and contract renewals will continue to allow operating costs to remain competitive and certain of the key fields profitable. Under these circumstances the Trust would attempt to seek alternatives including self-generation of its power requirements. However, it cannot guarantee that self-generation of power using its own product as fuel as an alternative to grid power will be either profitable or acceptable to landowners or regulators. A significant loss in profitability of key fields as a result of higher costs of electricity or lack of availability of electricity could affect future funds from operations and distributions.

Enterra's operations are subject to changes in governmental regulations and obtaining required regulatory approvals.

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of field and mine sites (including restrictions on production), and possible expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase Enterra's costs and have a material adverse impact on Enterra.

Although not strictly governmental or regulatory in nature, the implementation of International Financial Reporting Standards to replace Canadian GAAP effective January 1, 2011 (and as a potential reporting alternative to U.S. GAAP or resulting in the elimination of the requirement to reconcile to U.S. GAAP) may have an adverse impact on the Trust's financial results as reporting in its financial statements, and may require Enterra to amend its Credit Facilities to address the changes in accounting principles.

Enterra's operations are subject to credit risks with its commodity purchasers with its commodity contract counterparties.

The Trust sells its production either directly to a refinery, an intermediary or a mid-stream purchaser. The Trust does not sell all of its production to any one purchaser and in any one month the Trust varies to whom it sells its production depending on several factors including availability of production, availability of capacity and contractual agreements. Settlements usually occur between 20 to 40 days after the end of the month. While the Trust reviews the credit ratings of the purchaser on a frequent basis the Trust is exposed to the risk of loss of proceeds of production if the purchaser fails to pay for the production due to financial failure of the purchaser.

Risks Related to the Trust Structure and the Ownership of Trust Units and Debentures

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

Generally speaking, the Income Tax Act (Canada) (the "Tax Act") provides that a trust will permanently lose its "mutual fund trust" status (which is essential to the income trust structure) if it is established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of Unitholders must not be non-residents of Canada), unless at all times "all or substantially all" of the trust's property consisted of property other than certain taxable Canadian property (the "TCP Exception"). Based on the most recent information obtained through the Trust's transfer agent and financial intermediaries, in February 2009 an estimated 91% of the issued and outstanding Trust Units were held by non-residents of Canada (as defined in the Tax Act). The Trust is currently able to take advantage of the TCP Exception, and as a result, the Trust does not currently have a specific limit on the percentage of Trust Units that may be owned by non-residents. The Trust intends to continue to take the necessary measures in order to ensure that it continues to qualify as a mutual fund trust under the Tax Act. However, the Trust may not be able to take steps necessary to ensure that it maintains its mutual fund trust status. Even if it is successful in taking such measures, these measures could be adverse to certain holders of Trust Units, particularly non-residents of Canada. The board of EEC could impose a specific limit on the number of Trust Units that could be beneficially owned by non-residents of Canada, similar to the non-resident ownership restrictions in place for other income funds in Canada, or could implement a dual-class unit structure which would effectively limit the aggregate number of Trust Units that could be owned by non-residents of Canada. Steps could be taken to ensure that no additional Trust Units are issued or transferred to non-residents, including limiting or suspending the trading of the Trust Units.

Should the status as a mutual fund trust be lost or successfully challenged by the Canada Revenue Agency, certain adverse consequences may arise for the Trust and its Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be subject to a special tax under Part XII.2 of the Tax Act of 36% of its "designated income" (which would not include interest on the Series Notes or the CT Notes). Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are non-residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax;

- Trust Units and Debentures held by non-residents of Canada would become "taxable Canadian property". Non-resident holders would then be subject to Canadian tax reporting and payment requirements on any gains realized on a disposition of Trust Units or Debentures held by them;

- the Trust Units and Debentures may no longer constitute qualified investments under the Tax Act for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs"), or deferred profit sharing plans ("DPSPs") (collectively, "Exempt Plans"). If, at the end of any month, one of these Exempt Plans holds Trust Units or Debentures that are not a qualified investment, the plan must pay a tax equal to 1% of the fair market value of the Trust Units or Debentures at the time the Trust Units or Debentures were acquired by the Exempt Plan. An RRSP or RRIF holding Trust Units or Debentures that are not a qualified investment would be subject to taxation on income attributable to the Trust Units or Debentures, including the full amount of any capital gain from a disposition of the Trust Units or Debentures. If an RESP holds Trust Units or Debentures that are not a qualified investment, it may have its registration revoked by the Canada Revenue Agency; and

- the Trust would cease to be eligible for the capital gains refund mechanism available under the Tax Act.

Changes in tax and other legislation may adversely affect Unitholders.

Income tax laws, other legislation 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 its Unitholders. Tax authorities having jurisdiction over the Trust and its Unitholders may disagree with the manner in which it calculates its income for tax purposes or could change their administrative practices to the Trust's detriment or the detriment of the Unitholders.

On March 23, 2004, the Canadian federal government announced proposed changes to the Tax Act, which would have effectively eliminated, over a period of time, the TCP Exception currently relied on by most oil and gas trusts to maintain their mutual fund trust status. However, as the proposed changes only affected mutual fund trusts that held contractual oil and gas royalties, the proposals would not have had a direct impact on us. In response to submissions from and discussions with stakeholders, the Canadian federal government suspended the implementation of those proposed amendments.

On June 12, 2007, federal legislation was enacted implementing a new tax (the "SIFT Tax") on certain publicly traded income trusts and limited partnerships, referred to as "Specified Investment Flow-Through" ("SIFT") entities. For SIFTs in existence on October 31, 2006 (including Enterra), the SIFT Tax will become effective in 2011. If certain rules related to "undue expansion" are not adhered to ("the normal growth guidelines"), the SIFT Tax will apply prior to 2011. Under the SIFT Tax, distributions of certain types of income will not be deductible for income tax purposes by SIFTs in 2011 and thereafter and any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The SIFT Tax rate is currently 29.5 percent in 2011 and 28.0 percent thereafter.

As noted above, the Trust could become subject to these changes before 2011 if it experiences growth, other than "normal growth", before that time. Under the December 15, 2006 guidelines, the Trust was considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust Units and debt that is convertible into Trust Units, but does not include non-convertible debt) did not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the market value of the issued and outstanding Trust Units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately $408 million. The intervening periods and their respective safe harbour amounts were as follows:

(a) November 1, 2006 to December 31, 2007 – 40% of the Trust's market capitalization as of October 31, 2006;

(b) January 1, 2008 to December 31, 2008 – 20% of the Trust's market capitalization as of October 31, 2006;

(c) January 1, 2009 to December 31, 2009 – 20% of the Trust's market capitalization as of October 31, 2006;

(d) January 1, 2010 to December 31, 2010 – 20% of the Trust's market capitalization as of October 31, 2006.

The December 15, 2006 guidelines provided that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a Debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation (such as exchangeable shares), for Trust Units.

On November 28, 2008, the Canadian Minister of Finance tabled a Notice of Ways and Means Motion in the House of Commons which contained proposed changes to the SIFT conversion provisions under the Income Tax Act. On December 4, 2008, the Minister released explanatory notes for the Motion which also contained revisions to the Department of Finance "normal growth" guidelines for grandfathered SIFTs. The revision to the “normal growth” guidelines has accelerated the Trust’s allowance to issue new equity without “undue expansion” and allows the Trust to issue its remaining safe harbour amount after December 4, 2008 without considering the previous timeline set out by the Department of Finance.

While the revised guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to grow or maintain its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

There is no assurance that the Canadian federal government will not introduce other changes to the Tax Act directed at non-resident ownership which, given the Trust’s level of non-resident ownership, may result in the Trust losing its mutual fund trust status or could otherwise detrimentally affect it and the market price of the Trust Units.

The incurrence of tax by the Operating Subsidiaries could have a material adverse effect on the ability to pay distributions to Unitholders.

The Trust’s Operating Subsidiaries are subject to taxation in their respective taxation years on their respective taxable incomes for the year. The Operating Subsidiaries intend to deduct, in computing their income for tax purposes, the full amount available for deduction in each year associated with their income tax resource pools, undepreciated capital costs (“UCC”) and non-capital losses, if any. If there are not sufficient resource pools, UCC, non-capital losses carried forward, and interest to shelter the income of these Operating Subsidiaries, then cash taxes would be payable. In addition, there can be no assurance that taxation authorities will not seek to challenge the amount of resource pools, non-capital losses or interest expense relating to the Series Notes. If such a challenge were to succeed, it could materially adversely affect the amount of cash available for distribution to Unitholders and the market value of the Trust Units.

The cash available for distribution to Unitholders is ultimately sourced from these Operating Subsidiaries, some of which are in the United States and, as a result, subject to U.S. taxation. The Operating Subsidiaries that are subject to income taxation in the United States intend to deduct the full amount available in respect of depletion, depreciation, interest or other allowances under applicable law to reduce taxable income of such Operating Subsidiaries. There can be no assurances, however, that the taxation authorities of the United States will not challenge the amount of such deductions. If such a challenge were to succeed it could materially adversely affect the amount of cash available for distribution to Unitholders. Changes to the income tax law in the United States, changes to tax regulations in the United States, or changes in the interpretation or application of such law or regulations may result in increased taxation of funds generated in the United States and may adversely affect distributions to Unitholders and the market value of the Trust Units.

Interest and dividends that are received from the Operating Subsidiaries in the United States will be subject to United States withholding taxes the amount of which will be determined under applicable law, income tax treaties and regulations. In this regard, the United States Treasury Department has announced its intention to renegotiate one of the income tax treaties upon which the Trust relies for a reduction in withholding taxes on distributions from the Operating Subsidiaries in the United States. Changes in the applicable law, income tax treaties or regulations or in the application or interpretation thereof may increase such withholding taxes and may adversely affect distributions to Unitholders.

Unitholders may be required to pay taxes even if they do not receive any cash distributions.

Interest on the Series Notes and the CT 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 payable each year to Unitholders in order to reduce the Trust's taxable income to zero. The Trust Indenture provides that where, in a particular year, the Trust does not have sufficient available cash to distribute such an amount to the Unitholders, additional Trust Units will 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.

United States Unitholders may be limited in their ability to use the Canadian withholding tax as a credit against United States federal income tax and in their ability to claim the effect of certain other favourable United States income tax provisions.

It is expected that the Trust will be classified for United States federal income tax purposes as a partnership and not as a corporation. As a result, a citizen of the United States and each other person who is subject to United States federal income tax on a net income basis with respect to the Trust Units (each such person is referred to herein as a U.S. Holder) will generally include its share of the income, gain, loss, deduction and credit of the Trust on its United States federal income tax return in determining its liability for the United States federal income tax.

The Canadian income taxes that are withheld (currently at a 15 percent rate) from a distribution to a U.S. Holder on a Trust Unit may be deducted or, subject to limitations, used as a credit for United States federal income tax purposes. The limitation under United States law on foreign taxes that may be used as credits is calculated separately with respect to specific classes of income or "baskets". That is, the use of foreign taxes that are paid with respect to income in any such basket as a credit is limited to a percentage of the foreign source income in that basket. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are subject to the 15 percent rate (discussed below). Under rules of general application, a portion of a U.S. Holder's interest expense and other expenses can be allocated to, and thereby reduce, the foreign source income in any basket. Any gain that is recognized by a U.S. Holder on the sale of a Trust Unit that is recognized because a distribution thereon is in excess of basis in that security will generally constitute income from sources within the United States for U.S. foreign tax credit purposes and will therefore not increase the ability to use foreign taxes as credits.

For a U.S. Holder who is a non-corporate Unitholder, its share of the Trust's dividend income from its Canadian subsidiaries received before January 1, 2011 should be subject to United States federal income tax at a maximum rate of 15 percent provided that, among other things, (a) that the payor of the dividend is not classified as a PFIC during the taxable year in which such distribution is paid or the preceding taxable year, (b) that the U.S. Holder has satisfied certain holding period requirements, and (c) that the U.S. Holder has not made an election to treat the dividend as "investment income" for purposes of the investment interest deduction rules. In addition, the rate reduction will not apply to dividends if the recipient of a dividend is obligated to make related payments with respect to positions in substantially similar or related property. This disallowance applies even if the minimum holding period has been met. If the rate reduction is not applicable, the dividends would be subject to United States federal income taxation at ordinary income tax rates.

Each such U.S. Holder should discuss the effect of the limitations on the use of such Canadian taxes as a credit (including the effect of any ability to obtain a refund of such Canadian withholding tax in certain circumstances) and the limitations on obtaining the favourable United States federal rate reduction with its own advisers.

United States Unitholders who are generally tax exempt under United States law may recognize unrelated business taxable income (which is subject to United States federal income tax) in respect of their Trust Units.

Individual retirement accounts, other employee benefit plans and certain organizations that are generally exempt from United States federal income tax are subject to United States federal income tax on unrelated business taxable income, such as certain income from debt financed property, to the extent that such unrelated business taxable income for a taxable year is in excess of $1,000. The Trust has in the past and may in the future incur debt, the proceeds of which are invested in stock of EEC or another corporation. In that event, the dividends that the Trust receives from such corporation (which flow through to the holders of Trust Units while the Trust is a treated as a partnership for United States federal income tax purposes) will be unrelated business taxable income.

Such an individual retirement account or other tax exempt organization will generally also be subject to Canadian withholding tax on distributions that the Trust makes and will as a general matter be able to use all or a portion of that Canadian withholding tax as a credit against the United States federal income tax for which it is liable on any unrelated business taxable income in accordance with applicable law and with due regard to the applicable restrictions thereon. Such Canadian income tax will not as a general matter reduce or otherwise affect the Untied States federal income taxation of distributions that an individual retirement account or other employee benefit plans makes to its beneficiary or beneficiaries.

United States Unitholders may be subject to passive foreign investment company rules.

Although the Trust does not expect that any of the Trust's subsidiaries that are corporations for United States federal income tax purposes (or the Trust if it were to be a corporation for such purposes) is or has been a passive foreign investment company, or PFIC, there is no assurance in that regard.

A foreign corporation is, as a general matter, a PFIC if either (a) 75 percent or more of its gross income in a taxable year, including the pro rata share of the gross income of certain partially owned (whether directly or indirectly) corporations, is passive income (as defined in the pertinent provisions of the Code) or (b) 50 percent or more of its assets (including the pro rata share of the assets of any such partially owned subsidiary) are held for the production of, or to produce, passive income.

If the Trust or any of its subsidiaries were a PFIC, then a U.S. Holder who did not make an election to treat such corporation as a qualified electing fund (there is no assurance that it will be able to make such an election) would pay United States federal income tax on any "excess distributions" in respect of the PFIC stock (even if such U.S. Holder did not own stock in the PFIC directly) is allocated rateably over the U.S. Holder's holding period. The amounts allocated to the taxable year of the excess distribution and to any year before the relevant stock interest became a PFIC would be taxed as ordinary income. The amount allocated to each taxable year would be subject to United States federal income taxation at the highest rate in effect for individuals or corporations in such taxable year, as appropriate, and an interest charge would be imposed on the amount allocated to that taxable year. Distributions made in respect of the relevant PFIC stock interest during a taxable year (including any gain realized on the sale or other disposition of the PFIC stock, even if the cash proceeds thereof were not received) will be an excess distribution to the extent they exceed 125 percent of the average of the annual distributions in respect of said stock interest received by the U.S. Holder during the preceding three taxable years or the U.S. Holder's holding period, whichever is shorter. Moreover, any non-corporate Unitholder who is a U.S. Holder would not be entitled to the 15 percent maximum rate of Untied States federal income tax on any dividend that is received in respect of the stock in any such PFIC.

U.S. Holders are urged to consult their own tax advisors regarding the United States federal income tax consequences of classification as a PFIC of any corporation in which the Trust owns an interest (or the Trust) and of the consequences of such classification.

United States and other non-resident Unitholders may be subject to additional taxation.

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash distributions or other property paid by the Trust to Unitholders who are not residents of Canada, and these taxes may change from time to time. For instance, since January 1, 2005, a 15 percent withholding tax is applied to return of capital portion of distributions made to non-resident Unitholders.

The ability of United States and other non-resident investors to enforce civil remedies may be limited.

Enterra is a trust organized under the laws of Alberta, Canada, and EEC's principal offices are in Canada. Most of the Trust's directors and officers are residents of Canada and most of the experts who provide services to the Trust (such as its auditors and some of its independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and the assets of the Trust are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "Foreign Jurisdiction") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgement of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against EEC or any of its directors, officers or representatives of experts who are not residents of the Untied States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the Untied States federal securities laws or the securities laws of any state within the United States.

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 or the Trust Subsidiaries. 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 the Trust’s 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 its 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.

The limited liability of Unitholders of the Trust is uncertain.

Notwithstanding the fact that Alberta (the Trust’s governing jurisdiction) has adopted legislation purporting to limit Unitholder liability, because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held liable for obligations of the Trust in respect of contracts or undertakings which the Trust enters 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. Notwithstanding attempts to limit Unitholder liability, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. 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. There can be no assurance that the Alberta legislation purporting to limit Unitholder liability eliminates the risk that a Unitholder could be held liable for obligations of the Trust, and the legislation does not affect liability with respect to any act, default, obligation or liability that arose prior to July 1, 2004.

The cash redemption rights of Unitholders are limited.

Unitholders have a 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 obligation to pay cash in connection with redemption is subject to limitations. Any securities, which may be distributed to Unitholders in connection with 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.

There may be future dilution.

One of the objectives is to continually add to the Trust's reserves through acquisitions and through development. Since at present the Trust does not reinvest the majority of its cash flow, its success is, in part, dependent on its 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.

Unitholders will also suffer dilution as a result of the conversion of any of the Trust's Debentures, or if the Trust redeems outstanding Debentures for Trust Units or satisfies the obligation to pay interest on the Debentures by issuing additional Trust Units. See "Description of Debentures".

Prior distributions are not reflective of future distributions.

Historical distributions are not reflective of future distributions. Future distributions will be subject to review by, and are in the discretion of, the board of EEC. On September 17, 2007 the Trust suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt.

The actual amounts distributed, if any, will be based on the circumstances as they exist at the time and will be subject to a number of factors, many of which are beyond the Trust's control including, without limitation, the outlook for commodity prices and other macro-economic factors, the availability and cost of equity and debt financing, the size and nature of the prospects and opportunities available to us, and its financial position and commitments.

There may not always be an active trading market for the Trust Units and Debentures.

While there is currently an active trading market for the Trust Units in the United States and Canada and for the Debentures in Canada, there are no assurances that an active trading market will be sustained.

ITEM 4 – INFORMATION ON THE COMPANY

A. History and Development of the Company

Enterra Energy Trust

Enterra Energy Trust is an oil and gas trust established under the laws of the Province of Alberta pursuant to the Trust Indenture dated as of October 24, 2003, between Enterra Energy Corp. and Olympia Trust Company (the "Trust Indenture"). The Trust's assets consist of the securities of the Trust Subsidiaries and indirect interests in crude oil and natural gas properties through the Operating Subsidiaries. The Trust's head office is located at Suite 2700, 500 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6, Tel: (403) 263-0262. The Trust's registered office is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada T2P 5C5. Our agent for service of process in the United States is CT Corporation, 2610, 520 Pike Street, Seattle, Washington 98101.

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.

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.

History and Significant Acquisitions

2006 Acquisition of Oklahoma Assets

During the first six months of 2006, Enterra acquired oil and natural gas producing assets located in Oklahoma ("Oklahoma Assets"). The acquisition was completed through four closings. The first closing occurred on January 18, 2006 and represented approximately 1,300 BOE/d of production capacity. The second closing occurred on March 21, 2006 and represented approximately 3,700 BOE/d of production capacity. The final two closings occurred on April 4, 2006 and April 18, 2006 and represented approximately 1,300 BOE/d of production capacity. The assets consisted of approximately 80% natural gas and 20% light oil production and included approximately 53,000 net acres of land of which over 25,000 net acres were undeveloped. The purchase price of US$307.6 million was paid for through the issuance of 5,685,028 Trust Units valued at $116.5 million, $181.0 million of cash and closing costs of $10.0 million.

The current and anticipated production from the Oklahoma Assets is primarily from the Hunton Group carbonate formations and is derived through a de-pressuring of the formation via water production followed by hydrocarbon production. The Hunton Group is exploited at depths of approximately 1,500 metres using long, multi-leg horizontal wells. Enterra operates all of its related production, gathering and water disposal facilities. On June 27, 2006, a farm-out agreement was entered into with a U.S. Farmout Partner to exploit the undeveloped Hunton Group prospects.

2006 Property Swap with JED Oil Inc.

On September 28, 2006, Enterra closed a property swap agreement with JED Oil Inc. whereby Enterra swapped certain of its interests in properties in the Ferrier area of Alberta for interests of JED in common with Enterra's in East Central Alberta, the Desan area of Northeast British Columbia and the Ricinus area of Alberta. The swap was based on independent third party engineering evaluations and was effective July 1, 2006. The transaction also resulted in the termination of an Agreement of Business Principles between the Trust and JED whereby the Trust had a right of first refusal on properties that JED owned and JED had the ability to farm-in on the Trust's undeveloped lands. Concurrent with the swap, the Trust settled all amounts owing to JED.

2007 Acquisition of Trigger Resources Ltd.

On April 30, 2007, Enterra acquired all of the issued and outstanding shares of Trigger Resources Ltd.("Trigger Resources"). Trigger Resources shareholders received cash consideration of $63.3 million which was funded by the issuance of $40.0 million of 8.25% convertible Debentures that mature on June 30, 2012 and $29.2 million of Trust Units (4,945,000 trust units). Trigger Resources' oil and natural gas properties are located in west central and southwest Saskatchewan and, at the time of acquisition, added approximately 2,400 BOE/d (58% oil, 42% gas) to Enterra's production portfolio. The properties generally have 100% working interest with year round access and relatively low operating costs.

2007 Disposition of Non-core Assets

Enterra regularly evaluates asset acquisition and divestiture candidates. This practice, in conjunction with Enterra's debt reduction strategy, led the Trust in 2007 to review and identify assets deemed to be "non-core" to its ongoing operations. These assets were then publicly marketed in the fall of 2007. Enterra received numerous proposals for the assets marketed in addition to several unsolicited offers for non-core assets that had not been actively marketed. During 2007 certain Princess non-operated, Willesden Green and Little Bow properties were sold.

2008 Disposition of Non-core Assets

In 2008 Enterra's primary goals have been debt reduction, increased operational focus and efficiency and replacement of produced reserves. During 2008 the Trust closed the sale of non-core assets for proceeds of $39.6 million. Substantially all net proceeds were applied to debt reduction of the Trust.

Equity Offerings
2006 Financings

On March 3, 2006 Enterra filed a prospectus supplement for the issuance of up to 1,500,000 Trust Units at US$17.25 per unit. 275,000 Trust Units were issued under this prospectus supplement for proceeds of $5.4 million. Funds received from this financing were used for capital expenditures and for general corporate purposes.

On November 10, 2006 Enterra filed a short form prospectus for the issuance of 4,979,500 Trust Units at $8.10 per unit for proceeds of $40.3 million. Funds received from this financing were used to partially repay Enterra's then-existing bridge credit facilities.

On November 10, 2006 Enterra filed a short form prospectus for the issuance of $138,000,000 of 8% Debentures convertible into Trust Units at $9.25 per unit. The funds received from this financing were used to partially repay Enterra's then-existing bridge credit facilities. As at December 31, 2006 $57,669,000 of the convertible Debentures had been converted into 6,234,483 Trust Units.

2007 Financings

On April 11, 2007 Enterra filed a preliminary short form prospectus for the issuance of up to 4,945,000 Trust Units, inclusive of the underwriter's over-allotment option of 645,000 Trust Units, at a price of $5.90 per Trust Unit for gross proceeds of $29.2 million and $40.0 million of 8.25% Debentures convertible into Trust Units at a price of $6.80 per Trust Unit. The net proceeds of this issuance were used to finance the acquisition of Trigger Resources.

B. Business Overview

1. Nature of the Business

Enterra is an exploration and production oil and gas trust based in Calgary, Alberta, Canada with its United States operations office located in Oklahoma City, Oklahoma. Enterra's trust units are listed on the New York Stock Exchange (ENT) and Enterra's trust units and convertible debentures are listed on the Toronto Stock Exchange (ENT.UN, ENT.DB and ENT.DB.A).

Competitive Strengths

The Trust has a number of competitive strengths which will enhance the execution of its business strategy. Its competitive strengths include:

Diversified Production Base

The Trust's assets are principally located in four areas: north east British Columbia, Alberta, Saskatchewan and Oklahoma. While each area has different geological, production and infrastructure characteristics, in aggregate they have historically provided a stable source of production.

Large Portfolio of Development Projects

The Trust's properties contain a number of potential development projects, which supports the strategy of reserving a portion of funds from operations to invest in organic growth opportunities. Currently, there are a significant number of drilling opportunities on approximately 150,666 net acres of undeveloped land.

U.S. Platform Distinguishes the Trust from Other Canadian Oil & Gas Trusts

Based on average production during 2008, approximately 45% of the Trust's production is in the United States. The Trust's presence in both countries, in terms of people and assets, provides it with a broader range of opportunity, improves its perspective when evaluating projects or acquisitions, and reduces the dependence on the highly competitive Canadian market.

Commodity Price Hedges

As part of the active risk management program up to 50% of the projected gross production is hedged for up to 24 months in advance, the Trust has entered into a series of collars to reduce the impact of short-term fluctuations in crude oil and natural gas prices. The terms of the transactions are detailed in the notes to the 2008 consolidated annual financial statements and in Item 5 A. Operating Results - Commodity Contracts.

Experienced Management Team

In late 2007, the Trust had made several changes to its management team which has resulted in the formation of a strong, experienced and committed management team that has demonstrated its ability to identify and successfully execute the Trust's business plans.

Personnel

At December 31, 2008, the Trust employed or contracted 54 office personnel and 36 field operations personnel in its Canadian operations and 20 office personnel and 33 field operations personnel in its U.S. operations for a total of 143 employees.

Business Strategy During 2008

The Trust's portfolio of oil and gas properties is geographically diversified with producing properties located principally in Alberta, British Columbia, Saskatchewan and Oklahoma. Average production during 2008 was 10,283 boe per day comprised of approximately 63% natural gas and 37% crude oil and natural gas liquids ("NGL"). For 2009, production is expected to be approximately 47% oil and NGL and 53% natural gas due to new marketing contracts in Oklahoma that recognize more volume for the natural gas liquids in the production stream. Enterra has compiled a multi-year drilling inventory for its properties.

Enterra had some significant accomplishments during the year primarily in the areas of focus which were debt reduction and reserve replacement. Additional highlights were:

- Total bank debt was decreased to $95.5 million, a reduction of $76.5 million during the year, and has been further reduced by approximately $15.5 million since the end of 2008.
- Net debt was reduced to $52.4 million from $168.2 million at the end of 2007. This is a decrease of 69 percent.
- Funds from operations grew by 48 percent year over year to $107.3 million compared to $72.7 million for 2007.
- Production averaged 10,283 boe per day a decrease of 17 percent, despite the disposition of certain producing properties during the first half of the year.
- Finding and development costs declined by 25 percent to $8.24/boe (P+P excluding FDC) from $10.93/boe.
- Reserves produced during 2008 were replaced on a proved plus probable basis, through an effective capital spending program and the negotiation of new marketing agreements in Oklahoma.
- Participated in 42 wells (17.4 net) attaining a 97% success rate.

2. Markets and Revenues

Producers of oil negotiate sales contracts directly with oil purchasers, generally obtaining in a market price for oil. The price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and other contractual terms, as well as on the world price of oil. The price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, seasonal factors, weather conditions, the value of refined products, the supply/demand balance and other contractual terms

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,		
($000s)	2008	2007	2006
Canada	151,675	138,844	152,254
United States	103,593	84,984	81,338
Revenue	255,268	223,828	233,592

3. Seasonality

The business is somewhat seasonal in nature because a significant portion of the demand for natural gas is during the winter heating season in North America which can result in seasonal commodity price volatility. 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.

4. Volatility of Prices

The Trust's business, results of operations, financial condition and future growth are substantially dependent on the prevailing prices for its production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are based on world supply and demand and are subject to large fluctuations in response to relatively minor changes in supply or demand, whether the result of uncertainty or a variety of additional factors beyond the Trust's control including, without limitation, actions taken by OPEC and its adherence to agreed production quotas, war, terrorism, government regulation, social and political conditions, economic conditions, prevailing weather patterns and the availability of alternative sources of energy. Any substantial decline in the price of oil or natural gas could have a material adverse effect on the Trust's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of the properties, planned level of spending for exploration, and development and level of reserves. No assurance can be given that prices for oil or natural gas will be sustained at levels that will enable the Trust to operate profitably or make distributions.

5. Marketing Channels

The Trust uses financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from decline in oil and natural gas prices. In addition, the commodity hedging activities could expose the Trust 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 the hedging policies and procedures are not followed. Furthermore, it is unlikely that such hedging transactions will fully offset the risks of changes in commodity prices.

6. Patents and Licenses

Enterra is not dependent on any patents or licenses in order to conduct business.

7. 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. 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.

8. Government Regulation in Canada and the United States

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

Enterra's U.S. oil and natural gas operations are regulated by administrative agencies under statutory provisions of the state of Oklahoma where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Enterra's U.S. operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Pricing and Marketing - Oil

Crude oil exported from Canada is subject to regulation by the National Energy Board (the "NEB") and the Government of Canada. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain 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 20 years (in quantities of not more than 30,000 cubic metres per day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

The governments in the Canadian provinces where Enterra operates also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives

Canada:

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.

United States:
The royalties incurred by Enterra's Oklahoma operations are in the form of freehold royalties which are charged by the individual mineral owner and production taxes which are charge by the state of Oklahoma. The freehold royalty rate is determined by negotiations between the mineral owner and the lessee at the beginning of the lease. The production tax is charged by the Oklahoma Tax Commission and is based on either prices received or production volumes and is determined when the well is drilled. The current production tax rate is approximately seven percent. There is currently a six percent production tax rebate for the first 24 months of production on horizontal wells.

In late October 2007, the Alberta provincial government announced a new oil and gas royalty regime that took effect January 1, 2009. The Trust has assessed the impact of the new royalty regime and has determined that it will have a modest negative effect on its current portfolio of production and reserves in Alberta. Enterra now incorporates the new royalty scheme into its Alberta-based economic analysis prior to pursuing opportunities in the province. During 2008, approximately 31% of the Trust's production came from Alberta.

Tax Legislation
Income tax laws, other legislation 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 its Unitholders. Tax authorities having jurisdiction over the Trust and its Unitholders may disagree with the manner in which it calculates its income for tax purposes or could change their administrative practices to the Trust's detriment or the detriment of the Unitholders.

On March 23, 2004, the Canadian federal government announced proposed changes to the Tax Act, which would have effectively eliminated, over a period of time, the TCP Exception currently relied on by most oil and gas trusts to maintain their mutual fund trust status. However, as the proposed changes only affected mutual fund trusts that held contractual oil and gas royalties, the proposals would not have had a direct impact on Enterra. In response to submissions from and discussions with stakeholders, the Canadian federal government suspended the implementation of those proposed amendments.

On June 12, 2007, federal legislation was enacted implementing a new tax (the "SIFT Tax") on certain publicly traded income trusts and limited partnerships, referred to as "Specified Investment Flow-Through" ("SIFT") entities. For SIFTs in existence on October 31, 2006 (including Enterra), the SIFT Tax will become effective in 2011. If certain rules related to "undue expansion" are not adhered to ("the normal growth guidelines"), the SIFT Tax will apply prior to 2011. Under the SIFT Tax, distributions of certain types of income will not be deductible for income tax purposes by SIFTs in 2011 and thereafter any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The SIFT Tax rate is currently 29.5 percent in 2011 and 28.0 percent thereafter.

As noted above, the Trust could become subject to these changes before 2011 if it experiences growth, other than "normal growth", before that time. Under the December 15, 2006 guidelines, the Trust was considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust Units and debt that is convertible into Trust Units, but does not include non-convertible debt) did not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the market value of the issued and outstanding Trust Units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately $408 million. The intervening periods and their respective safe harbour amounts were as follows:

a) November 1, 2006 to December 31, 2007 – 40% of the Trust's market capitalization as of October 31, 2006;

b) January 1, 2008 to December 31, 2008 – 20% of the Trust's market capitalization as of October 31, 2006;

c) January 1, 2009 to December 31, 2009 – 20% of the Trust's market capitalization as of October 31, 2006;

d) January 1, 2010 to December 31, 2010 – 20% of the Trust's market capitalization as of October 31, 2006.

The December 15, 2006 guidelines provided that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a Debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation (such as exchangeable shares), for Trust Units.

On November 28, 2008, the Canadian Minister of Finance tabled a Notice of Ways and Means Motion in the House of Commons which contained proposed changes to the SIFT conversion provisions under the Income Tax Act. On December 4, 2008, the Minister released explanatory notes for the Motion which also contained revisions to the Department of Finance "normal growth" guidelines for grandfathered SIFTs. The revision to the "normal growth" guidelines has accelerated the Trust's allowance to issue new equity without "undue expansion" and allows the Trust to issue its remaining safe harbour amount after December 4, 2008 without considering the previous timeline set out by the Department of Finance.

While the revised guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to grow or maintain its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

There is no assurance that the Canadian federal government will not introduce other changes to the Tax Act directed at non-resident ownership which, given the Trust's level of non-resident ownership, may result in the Trust losing its mutual fund trust status or could otherwise detrimentally affect it and the market price of the Trust Units.

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. In Oklahoma land sales are done privately between the individual mineral owner and Enterra.

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.

The Trust's operations in Canada and the United States are subject to stringent government laws and regulations regarding pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations may impose administrative, civil and criminal penalties as well as joint and several, strict liability for failure to comply, and generally require the Trust to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The applicable regulatory agencies review the Trust's compliance with applicable laws and regulations. Monitoring and reporting programs, as wells as inspections and assessments for environment, health and safety performance in day-to-day operations, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event, and remediation/reclamation programs are in place and utilized to restore the environment.

The Trust currently owns or leases, and has in the past owned or leased, properties that have been used for oil and natural gas exploration and production activities for many years. Although operating and disposal practices have been used that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by the Trust. In addition, some of these properties have been operated by third parties, whose treatment and disposal or release of petroleum hydrocarbons and wastes were not under the Trust's control, including when these properties were owned or leased by any previous owner(s). These properties and the materials disposed or released on them may be subject to joint and several, strict liability laws at the federal, state and/or provincial levels. Under such laws, the Trust could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination. The Trust is currently involved in several remediation projects but it does not believe these costs to be material to the Trust's operations or financial position.

During 2008, the Trust experienced three salt water spills at water handling facilities in Oklahoma. In aggregate, in excess of 200,000 bbls of produced water is moved daily to facilitate hydrocarbon production. The increased drilling activity in 2008 coupled with the prolific nature of many of these new wells has resulted in almost double the daily water production as compared to 2007. As such, the Trust took steps over 2008 to reduce the environmental risk from potential spills. These improvements included enhancements to both the alarm systems as well as to the on-site spill containment.

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 may be distributed to its Unitholders. Enterra's Trustee may, upon the recommendation of the board of EEC in respect of any period, declare payable to the Unitholders all or any part of the net income of the Trust. The Trust's primary sources of cash flow are payments of interest and repayments of principal from the Trust Subsidiaries in respect of indebtedness of each of those entities to and in favour of the Trust. 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" in Item 3 D.

In September 17, 2007 Enterra suspended its monthly distributions in order to redirect its cash flow to the repayment of its outstanding debt. In June 2008, Enterra stated that it would extend the distribution suspension until at least November 2008 and that under the current credit facility Enterra is restricted from paying distributions while it has the second-lien facility in place. As a result, no distributions were paid in 2008.

Enterra continues to assess how cash flows generated from operations are used. In light of the current economic uncertainty, Enterra has deferred capital spending and has increased its cash position and reduced debt. Enterra will maintain a conservative approach during 2009 and assess how best to allocate cash between capital spending, debt repayment and distributions.

Enterra currently minimizes cash income taxes in corporate subsidiaries by maximizing deductions. However, in future periods, there may be cash income taxes if deductions in the corporate entities are not sufficient to eliminate taxable income. Taxability of Enterra was, until September 2007, passed on to unitholders in the form of taxable distributions. Enterra anticipates that, commencing in 2011 new tax legislation that will subject the Trust to a tax in a manner similar to corporations will decrease the amount of cash available for distribution and thus reduce any potential cash distributions to unitholders.

Series Notes

The Series Notes are unsecured debt obligations of the Operating Subsidiaries and are subordinated to all of the Trust's Senior Indebtedness. They bear interest at various annual rates, expire at various dates up to 2033 and the principal amounts of the notes vary as additional funds are loaned by the Trust to the Operating Subsidiaries or as principal repayments are made on the notes. Interest for each month is payable monthly in arrears on the 15th day of the month.

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 ratably 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.

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.

The Trust Indenture

Enterra's principal undertaking is to issue Trust Units and to acquire and hold debt instruments, securities, royalties and other interests. The Operating Subsidiaries carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto. Cash flow from the properties is flowed from the Trust Subsidiaries to the Trust primarily through (i) payments of interest and principal in respect of the Series Notes, (ii) payments of interest and principal in respect of the CT Notes, and (iii) dividends declared on the common shares of certain Operating Subsidiaries and/or redemptions of preferred shares of certain Operating Subsidiaries, which amounts are transferred from EECT to the Trust as payments of interest or principal on the CT Notes. Cash flow received by the Trust is distributed to its Unitholders on a monthly basis at the discretion of the Trust.

Issuance of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants (including so called "special warrants" which may be exercisable for no additional consideration) and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee may determine, including, without limitation, installment or subscription receipts. Enterra's Trust Indenture also provides that the Trustee may authorize the creation and issuance of Debentures, notes and other evidences of indebtedness of the Trust, which Debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as the Trustee may determine.

Special Voting Rights

The Trust Indenture allows for the creation and issuance of an unlimited number of Special Voting Rights which enable the Trust to provide voting rights to holders of securities issued by certain Trust Subsidiaries (such as exchangeable shares) that may be issued by subsidiaries of the Trust in connection with exchangeable share transactions.

Holders of Special Voting Rights are not entitled to any distributions of any nature whatsoever from the Trust. Each holder is entitled to attend and vote at meetings of Unitholders according to the terms of the instrument pursuant to which the Special Voting Rights are issued. Each holder of outstanding Special Voting Rights is entitled to that number of votes equal to the number of votes attached to the Trust Units for which the securities relating to such Special Voting Rights held by such holder are exchangeable, exercisable or convertible. Holders of Special Voting Rights are also entitled to receive all notices, communications or other documentation required to be given or otherwise sent to Unitholders. 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.

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 or of any other kind whatsoever, including taxes payable, in connection with the Trust or its obligations or affairs and, in the event that a court determines that 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 terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation.

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

Redemption Right

The 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 and 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 will only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (iii) 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 (iv) 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 Trust will pay the aggregate Market Redemption Price in respect of any Trust Units surrendered for redemption during any calendar month by cheque 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 the Trust may, at 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 will be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series 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 Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to 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 Notes and the issuance of any Redemption Notes will 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 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 Notes or Redemption Notes, as the case may be, 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 NYSE and are not traded or quoted on any other stock exchange or market which EEC 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 EEC 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 will 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 Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of the Trust Units to dispose of their Trust Units. Series Notes or Redemption Notes, which may be distributed in specie to Unitholders in connection with redemption, will not be listed on any stock exchange and no market is expected to develop in such Series Notes or Redemption Notes. Series 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.

Reporting to Unit Holders

An independent recognized firm of chartered accountants audits the financial statements of the Trust annually. The audited consolidated 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 Canadian securities legislation. The year-end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

The Trust is subject to the reporting requirements of the U.S. Exchange Act applicable to foreign private issuers, and in connection therewith will file or submit reports, including annual reports and other information with 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 are also available to the public on the SEC's web site at www.sec.gov.

Meetings of Unitholders

The Trust Indenture provides that meetings of the Trust's Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors, 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 the 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) EEC; 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 Enterra's Unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders and holders of Special Voting Rights 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 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 the Unitholders in accordance with the requirements of applicable laws.

Voting of EEC trust units

There is an annual general meeting of the holders of EEC trust units. Immediately following this meeting is a Trustee meeting 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

Enterra's Trustee is prohibited from authorizing or approving:

- 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;

- any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction as the case may be, of the Trust with any other person, except: (i) in conjunction with an internal reorganization as referred to in the bulleted paragraph above, or (ii) where immediately following completion of such transaction, the holders (or affiliates thereof) of equity interests in such other person (such holder being determined immediately prior to the entering into of such transaction) do not hold, directly or indirectly (on a fully diluted basis), more than 50% of, as applicable, (x) the issued and outstanding voting rights attributable to securities of the issuer which results from such transaction, or (y) the issued and outstanding Trust Units; or

- 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 the first bulleted paragraph 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 EECT to vote any shares of EEC in respect of:

- any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by EEC, the Trust or EPP, except in conjunction with an internal reorganization of the direct or indirect assets of EEC, EECT or EPP, as the case may be, as a result of which EECT 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;

- any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction as the case may be, of the Trust with any other person, except: (i) in conjunction with any internal reorganization as referred to in the bulleted paragraph above, or (ii) where immediately following completion of such transaction, the holders (or affiliates thereof) of equity interests in such other person (such holders being determined immediately prior to the entering into of such transaction) do not hold, directly or indirectly (on a fully diluted basis), more than 50% of, as applicable, (x) the issued and outstanding voting rights attributable to securities of the issuer which results from such transaction, or (y) the issued and outstanding Trust Units;

- the winding up, liquidation or dissolution of EEC, EECT or EPP prior to the end of the term of EECT, except in conjunction with an internal reorganization as referred to in the first bulleted paragraph above;

- any amendment to the articles of EEC to increase or decrease the minimum or maximum number of directors;

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

- any material amendment to the EECT indenture or the EPP partnership agreement which may be prejudicial to EECT;

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

Finally, the Trustee is prohibited from authorizing EECT to vote any shares of EEC 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 EEC by ordinary resolution or special resolution, without the prior approval of the Trust's 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 the Unitholders. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions 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 was until the third annual meeting of Unitholders in May, 2006. At the June 2007 annual meeting, the Unitholders re-appointed Olympia Trust Company as 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 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.

Takeover Bid

The Trust Indenture contains provisions to the effect that if a takeover bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the

Trust Units held by Unitholders who did not accept the take-over bid on the terms offered by the offeror. In the event of a take-over bid for the Trust Units, any holder of a security exchangeable directly or indirectly into Trust Units may, unless prohibited by the terms and conditions of such exchangeable security, convert, exercise or exchange such exchangeable security for the purpose of tendering Trust Units to the take-over bid, unless an identical offer is made by the offeror to purchase such exchangeable security.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents are not 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 EEC, or any other person to whom the Trustee has, with the consent of EEC, 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 EEC 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. On May 18, 2006, the Unitholders by Special Resolution, approved an amendment to the Trust Indenture which somewhat broadens the ability of the Trust to undertake certain types of corporate transactions without the necessity of obtaining Unitholder approval, unless otherwise required by applicable law. Enterra's Trustee may, without the approval of the Unitholders, amend the Trust Indenture for the purpose of:

- ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority;

- ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) and paragraph 132(7)(a) of the Tax Act as from time to time amended or replaced;

- 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;

- 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, or any applicable law or regulation of any jurisdiction, provided that in the opinion of Enterra's Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby;

- 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 Enterra's Unitholders are not prejudiced thereby;

- 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; and

- ensuring that additional protection is provided for the interests of Unitholders as the Trustee may consider expedient.

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: (i) a meeting may only be held for the purpose of such a vote if requested in writing by the holders of not less than 20% of the outstanding Trust Units and Special Voting Rights; (ii) a quorum of the holders of 50% of the issued and outstanding Trust Units and Special Voting Rights must be present in person or by proxy; and (iii) the termination must be approved by Special Resolution of Enterra's Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trust will 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 Enterra's Unitholders in respect of the termination authorized pursuant to the Special Resolution of 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 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.

Description of Debentures

General

Enterra's Debentures were issued under a Debenture trust indenture (the "Debenture Indenture") dated as of November 21, 2006 and April 26, 2007 among the Trust, EEC and Olympia Trust Company (the "Debenture Trustee"). An unlimited number of Debentures are authorized for issue.

The Debentures are dated as of November 21, 2006 and April 26, 2007 respectively. They were issuable only in denominations of $1,000 and integral multiples thereof. The maturity date for the Debentures is December 31, 2011 and June 30, 2012 respectively.

The Debentures bear interest from the date of issue at 8.0% and 8.25% per annum, which is payable semi-annually in arrears on June 30 and December 31 in each year, commencing June 30, 2007 and December 31, 2007 respectively.

The principal amount of the Trust's Debentures is payable in lawful money of Canada or, at the Trust's option and subject to applicable regulatory approval, by payment of Trust Units as further described below under "Payment upon Redemption or Maturity" and "Redemption and Purchase". The interest on these Debentures is payable in lawful money of Canada including, at the Trust's option and subject to applicable regulatory approval, in accordance with the Unit Interest Payment Election as described below under "Interest Payment Option".

The Debentures are direct obligations of the Trust and are not secured by any mortgage, pledge, hypothec or other charge and are subordinated to other liabilities of the Trust as described under "Subordination". Other than as described herein, the Debenture Indenture do not restrict the Trust from incurring additional indebtedness or liabilities or from mortgaging, pledging or charging its properties to secure any indebtedness.

Conversion Privilege

Enterra's Debentures are convertible at the holder's option into fully paid and non-assessable Trust Units at any time prior to the close of business on the earlier of the maturity date and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $9.25 and $6.80 per Trust Unit respectively, being a conversion rate of 108.1081 and 147.0588 Trust Units for each $1,000 principal amount of Debentures respectively. Holders converting their Debentures will receive all accrued and unpaid interest thereon in cash to the date of conversion.

Subject to the provisions thereof, the Debenture Indenture provides for the adjustment of the conversion price in certain events including: (a) the subdivision or consolidation of the outstanding Trust Units; (b) the distribution of the Trust Units to holders of Trust Units by way of distribution or otherwise other than an issue of securities to holders of Enterra's Trust Units who have elected to receive distributions in securities of the Trust in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to all or substantially all of the holders of the Trust Units entitling them to acquire Enterra's Trust Units or other securities convertible into the Trust Units at less than 95% of the then current market price (as defined below) of the Trust Units; and (d) the distribution to all or substantially of the holders of Enterra's Trust Units of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the conversion price in respect of any event described in (b), (c) or (d) above if the holders of the Trust's Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. The Trust is not required to make adjustments in the conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%.

The term "current market price" is defined in the Debenture Indenture to mean the weighted average trading price of the Trust Units on the Toronto Stock Exchange for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

In the case of any reclassification or capital reorganization (other than a change resulting from consolidation or subdivision) of Enterra's Trust Units or in the case of any consolidation, amalgamation or merger of the Trust with or into any other entity, or in the case of any sale or conveyance of the properties and assets of the Trust as, or substantially as, an entirety to any other entity, or a liquidation, dissolution or winding-up of the Trust, the terms of the conversion privilege shall be adjusted so that each holder of a Debenture shall, after such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding-up, be entitled to receive the number of Trust Units such holder would be entitled to receive if on the effective date thereof, it had been the holder of the number of Trust Units into which the Debenture was convertible prior to the effective date of such reclassification, capital reorganization, consolidation, amalgamation, merger, sale, conveyance, liquidation, dissolution or winding-up.

No fractional Trust Units will be issued on any conversion but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Redemption and Purchase

Enterra's Debentures are not redeemable on or before December 31, 2009 and June 30, 2010 respectively. On or after January 1, 2010 and July 1, 2010 respectively and prior to maturity, the Debentures may be redeemed in whole or in part from time to time at the Trust's option on not more than 60 days and not less than 30 days notice, at a Redemption Price of $1,050 per Debenture after December 31, 2009 and June 30, 2010 respectively, on or before December 31, 2010 and June 30, 2011 respectively, at a Redemption Price of $1,050 per Debenture and on or after January 1, 2011 and July 1, 2011 respectively and prior to maturity at a Redemption Price of $1,025 per Debenture, in each case, plus accrued and unpaid interest thereon, if any.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable.

Enterra has the right to purchase the Debentures in the market, by tender or by private contract.

Payment upon Redemption or Maturity

On redemption or at maturity, the Trust will, subject to the Trust's option to make such repayment in Trust Units as described below, repay the indebtedness represented by these Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, together with accrued and unpaid interest thereon. The Trust may, at its option, on not more than 60 and not less than 40 days prior notice and subject to applicable regulatory approval, elect to satisfy the obligation to pay the applicable Redemption Price of the Debentures which are to be redeemed or the principal amount of the Debentures which have matured, as the case may be, by issuing freely tradable Trust Units to the holders of the Debentures. Any accrued and unpaid interest thereon will be paid in cash. The number of Trust Units to be issued will be determined by dividing the aggregate Redemption Price of the outstanding Debentures which are to be redeemed or the principal amount of the outstanding Debentures which have matured, as the case may be, by 95% of the weighted average trading price of Enterra's Trust Units for the 20 consecutive trading days ending on the fifth trading day preceding the date fixed for redemption or the maturity date, as the case may be. No fractional Trust Units will be issued on redemption or maturity but in lieu thereof the Trust shall satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Subordination

The payment of the principal and premium, if any, of, and interest on, Enterra's Debentures is subordinated in right of payment, as set forth in the Debenture Indenture, to the prior payment in full of all of the Senior Indebtedness and indebtedness to the Trust's trade creditors. "Senior Indebtedness" is defined in the Debenture Indenture as the principal of and premium, if any, and interest on and other amounts in respect of all of the Trust's indebtedness (whether outstanding as at the date of the Debenture Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future Debentures or other instruments of the Trust which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be pari passu with, or subordinate in right of payment to, the Trust's Debentures. Subject to statutory or preferred exceptions or as may be specified by the terms of any particular securities, each Debenture issued under the Debenture Indenture ranks pari passu with each other Debenture, and with all of the other present and future subordinated and unsecured indebtedness except for sinking provisions (if any) applicable to different series of Debentures or similar types of obligations.

The Debenture Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Trust, or to property or assets, or in the event of any proceedings for Enterra's voluntary liquidation, dissolution or other winding-up, whether or not involving insolvency or bankruptcy, or any marshalling of the Trust's assets and liabilities, then those holders of Senior Indebtedness, including to trade creditors, will receive payment in full before the holders of the Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Debenture Indenture also provides that the Trust cannot make any payment, and the holders of the Debentures are not entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including without any limitation by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures or (b) at any time when an event of default has occurred under the Senior Indebtedness and is continuing and the notice of such event of default has been given by or on behalf of the holders of Senior Indebtedness to us, unless the Senior Indebtedness has been repaid in full.

The Debentures are also effectively subordinate to claims of creditors of the Trust Subsidiaries except to the extent the Trust is a creditor of such subsidiaries ranking at least pari passu with such other creditors. Specifically, the Trust's Debentures will be effectively subordinated in right of payment to the prior payment in full of all indebtedness under the Revolving and Operating Credit Facilities.

Priority over Trust Distributions

Enterra's Trust Indenture provides that certain expenses of the Trust must be deducted in calculating the amount to be distributed to the Unitholders. Accordingly, the funds required to satisfy the interest payable on the Debentures, as well as the amount payable upon redemption or maturity of the Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to the Unitholders.

Change of Control of the Trust

Within 30 days following the occurrence of a change of control of the Trust involving the acquisition of voting control or direction over 66 2/3% or more of Enterra's Trust Units (a "Change of Control"), the Trust is required to make an offer in writing to purchase all of the Debentures then outstanding (the "Offer"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest (the "Offer Price").

The Debenture Indenture contains notification and repurchase provisions requiring the Trust to give written notice to the Debenture Trustee of the occurrence of a Change of Control within 30 days of such event together with the Offer. The Debenture Trustee will thereafter promptly mail to each holder of Debentures a notice of the Change of Control together with a copy of the Offer to repurchase all the outstanding Debentures.

If 90% or more in aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Trust pursuant to the Offer, the Trust will have the right and obligation to redeem all the remaining Debentures at the Offer Price. Notice of such redemption must be given by the Trust to the Debenture Trustee within 10 days following the expiry of the Offer, and as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered pursuant to the Offer.

Interest Payment Option

The Trust may elect, from time to time, to satisfy its obligation to pay interest on the Debentures (the "Interest Obligation"), on the date it is payable under the Debenture Indenture (an "Interest Payment Date"), by delivering sufficient Trust Units to the Debenture Trustee to satisfy all or any part of the Interest Obligation in accordance with the Debenture Indenture (the "Unit Interest Payment Election"). The Indenture provides that, upon such election, the

Debenture Trustee shall (a) accept delivery from the Trust of the Trust Units, (b) accept bids with respect to, and consummate sales of, such Trust Units, at the Trust's absolute discretion, (c) invest the proceeds of such sales in short-term permitted government securities (as will be defined in the Debenture Indenture) which mature prior to the applicable Interest Payment Date, and use the proceeds received from such permitted government securities, together with any proceeds from the sale of Trust Units not invested as aforesaid, to satisfy the Interest Obligation, and (d) perform any other action necessarily incidental thereto.

The Debenture Indenture sets forth the procedures to be followed by the Trust and the Debenture Trustee in order to effect the Unit Interest Payment Election. If a Unit Interest Payment Election is made, the sole right of a holder of the Debentures in respect of interest is to receive cash from the Debenture Trustee out of the proceeds of the sale of Trust Units (plus any amount received by the Debenture Trustee from the Trust attributable to any fractional Trust Units) in full satisfaction of the Interest Obligation, and the holder of such Debentures has no further recourse to the Trust in respect of the Interest Obligation.

Neither the making of the Unit Interest Payment Election nor the consummation of sales of Trust Units will (a) result in the holders of the Trust's Debentures not being entitled to receive on the applicable Interest Payment Date cash in an aggregate amount equal to the interest payable on such Interest Payment Date, or (b) entitle such holders to receive any of the Trust Units in satisfaction of the Interest Obligation.

Events of Default

The Debenture Indenture provides that an event of default ("Event of Default") in respect of the Trust's Debentures will occur if any one or more of the following described events has occurred and is continuing with respect to the Debentures: (a) failure for 10 days to pay interest on the Debentures when due; (b) failure to pay principal or premium, if any, when due on the Debentures, whether at maturity, upon redemption, by declaration or otherwise; (c) certain events of bankruptcy, insolvency or reorganization under bankruptcy or insolvency laws; or (d) default in the observance or performance of any material covenant or condition of the Debenture Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to the Trust specifying such default and requiring the Trust to rectify the same. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall upon request of holders of not less than 25% in principal amount of the outstanding Debentures, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of a majority of the principal amount of the Debentures then outstanding may, on behalf of the holders of all Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Debentures

The Debenture Indenture contains provisions to the effect that if an offer is made for the Trust's Debentures which is a take-over bid for the Debentures within the meaning of the Securities Act (Alberta) and not less than 90% of the Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by the holders of Debentures who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of the Debentures as well as any other series of Debentures that may be issued under the Debenture Indenture may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture contains certain provisions which make binding on all Debenture holders resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the outstanding Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the outstanding Debentures. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

Limitation on Issuance of Additional Debentures

The Debenture Indenture provides that the Trust shall not issue additional convertible Debentures of equal ranking if the principal amount of all of the issued and outstanding convertible Debentures exceeds 25% of the Total Market Capitalization of the Trust immediately after the issuance of such additional convertible Debentures. "Total Market Capitalization" is defined in the Debenture Indenture as the total principal amount of all of Enterra's issued and outstanding Debentures which are convertible at the option of the holder into Trust Units plus the amount obtained by multiplying the number of issued and outstanding Trust Units by the current market price of the Trust Units on the relevant date.

Book-Entry System for Debentures

The Trust's Debentures have been issued in "book-entry only" form and must be purchased or transferred through a participant (a "Participant") in the depository service of The Canadian Depository of Securities Limited ("CDS"). The Debentures are evidenced by a single book-entry only certificate. Registration of interests in and transfers of the Debentures are made only through the depository service of CDS.

Except as described below, a purchaser acquiring a beneficial interest in the Debentures (a "Beneficial Owner") will not be entitled to a certificate or other instrument from the Debenture Trustee or CDS evidencing that purchaser's interest therein, and such purchaser will not be shown on the records maintained by CDS, except through a Participant.

The Trust assumes no liability for: (a) any aspect of the records relating to the beneficial ownership of the Debentures held by CDS or the payments relating thereto; (b) maintaining, supervising or reviewing any records relating to the Debentures; or (c) any advice or representation made by or with respect to CDS and relating to the rules governing CDS or any action to be taken by CDS or at the direction of its Participants. The rules governing CDS provide that it acts as the agent and depositary for the Participants. As a result, Participants must look solely to CDS and Beneficial Owners must look solely to Participants for the payment of the principal and interest on the Debentures paid by the Trust or on the Trust's behalf to CDS.

The Debentures are issued to Beneficial Owners in fully registered and certificate form (the "Debenture Certificates") only if: (a)are required to do so by applicable law; (b) the book-entry only system ceases to exist; (c)or CDS advises the Debenture Trustee that CDS is no longer willing or able to properly discharge its responsibilities as depositary with respect to the Debentures and the Trust unable to locate a qualified successor; (d) the Trust, at its option, decides to terminate the book-entry only system through CDS; or (e) after the occurrence of an Event of Default, Participants acting on behalf of Beneficial Owners representing, in the aggregate, more than 25% of the aggregate principal amount of the Debentures then outstanding advise CDS in writing that the continuation of a book-entry only system through CDS is no longer in their best interest provided the Debenture Trustee has not waived the Event of Default in accordance with the terms of the Debenture Indenture.

Upon the occurrence of any of the events described in the immediately preceding paragraph, the Debenture Trustee will be required to notify CDS, for and on behalf of Participants and Beneficial Owners, of the availability through CDS of Debenture Certificates. Upon surrender by CDS of the single certificate representing the Debentures and receipt of instructions from CDS for the new registrations, the Debenture Trustee will deliver the Debentures in the form of Debenture Certificates and thereafter the Trust will recognize the holders of such Debenture Certificates as Debenture holders under the Debenture Indenture.

Interest on the Debentures will be paid directly to CDS while the book-entry only system is in effect. If Debenture Certificates are issued, interest will be paid by cheque drawn on the Trust and sent by prepaid mail to the registered holder or by such other means as may become customary for the payment of interest. Payment of principal, including payment in the form of Enterra's Trust Units if applicable, and the interest due, at maturity or on a redemption date, will be paid directly to CDS while the book-entry only system is in effect. If Debenture Certificates are issued, payment of principal, including payment in the form of the Trust Units if applicable, and interest due, at maturity or on a redemption date, will be paid upon surrender thereof at any office of the Debenture Trustee or as otherwise specified in the Debenture Indenture.

Exchangeable Shares

EEC Exchangeable Shares

As of December 31, 2006, there were 16,337 EEC Exchangeable Shares outstanding. On January 31, 2007, all EEC Exchangeable Shares then outstanding were automatically redeemed. On and after January 31, 2007, the rights of former holders of EEC Exchangeable Shares were limited to receiving those Trust Units to which they are entitled as a result of the redemption.

RMAC Exchangeable Shares

As of December 31, 2006, there were 66,720 RMAC Exchangeable Shares outstanding. On January 19, 2007, all RMAC Exchangeable Shares then outstanding were automatically redeemed. On and after January 19, 2007, the rights of former holders of RMAC Exchangeable Shares were limited to receiving those Trust Units to which they are entitled as a result of the redemption.

RMG Exchangeable Shares

On June 1, 2006, all RMG Exchangeable Shares then outstanding were automatically redeemed. On and after June 1, 2006, the rights of former holders of RMG Exchangeable Shares were limited to receiving those Trust Units to which they are entitled as a result of the redemption. As of December 31, 2006, there were zero RMG Exchangeable Shares outstanding.

C. Organizational Structure

Enterra Energy Trust

Enterra Energy Trust is an oil and gas trust established under the laws of the Province of Alberta pursuant to the Trust Indenture. The Trust's assets consist of the securities of the Trust Subsidiaries and indirect interests in crude oil and natural gas properties through the Operating Subsidiaries.

Enterra Energy Commercial Trust

EECT is an unincorporated commercial trust established under the laws of the Province of Alberta. The Trust owns all of the issued and outstanding EECT Units. EECT holds, directly or indirectly, all of the outstanding shares and interests of the Operating Subsidiaries.

Enterra Energy Corp.

EEC is a corporation incorporated under the ABCA. EEC is one of the Operating Subsidiaries and acts as administrator of the Trust pursuant to the Administration Agreement. EECT owns all of the issued and outstanding shares of EEC. On January 31, 2007, EEC amalgamated with EPC to form EEC.

Enterra Production Partnership

EPP was formed as a general partnership under the laws of the Province of Alberta on August 16, 2001. The partners of the Partnership are EEC and Enterra Energy Partner Corp. EEC manages the operations of EPP.

Enterra Energy Partner Corp.

EEPC is a corporation incorporated under the ABCA. EEPC is a holding company wholly owned by EEC which holds an interest in EPP.

Enterra US Acquisitions Inc.

Enterra US Acqco is a corporation incorporated under the Delaware GCL. All of the United States assets and operations are held and conducted indirectly through Enterra US Acqco.

Enterra Acquisitions Corp.

EAC is a corporation incorporated under the Delaware GCL. Enterra US Acqco owns all of the issued and outstanding shares of EAC.

Altex Energy Corporation

Altex is a corporation incorporated under the Delaware GCL. Altex is a wholly owned subsidiary of EAC.

Organizational Chart
The following chart illustrates the Corporate structure as at December 31, 2008.

All of the entities shown above that are below "Enterra Energy Trust" are, direct or indirect, wholly-owned subsidiaries of the Trust.

D. Property, Plants and Equipment

Enterra's Canadian core areas include a variety of assets in Western Canada in the provinces of British Columbia, Alberta and Saskatchewan. In northeast British Columbia Enterra has a significant producing area at Desan. In Alberta, the major producing areas are: Clair, Provost-Alliance-Wainwright, Princess and Ricinus. In west-central Saskatchewan, the majority of production is located in the Primate and Liebenthal areas. In the United States, Enterra's producing assets are located mainly in Grant, Lincoln and Logan Counties in Oklahoma. Enterra also has an inventory of minor producing assets, minor royalty interests, and various prospects of an exploitation and exploration nature on undeveloped lands in Alberta, British Columbia, Saskatchewan and Oklahoma, the development of which could significantly increase the size of the existing production and reserve base.

Description of Material Tangible Property

Northeast British Columbia

The northeast British Columbia assets consist of the producing property in Desan and the undeveloped properties at Peggo.

Desan
The Desan property is located 75 miles northeast of Fort Nelson, British Columbia in the gas producing greater Sierra area. The primary producing zone is the Jean Marie formation. This regional carbonate has historically been the target for sweet dry gas and provides very good initial production and a long life of slow decline ideally suited to predictable cash flow. Although the Jean Marie is regionally gas charged the best reserves are discovered through detailed geological and geophysical analysis, pinpointing areas of secondary porosity associated with structures. The Jean Marie, at 1,300 m (4,250 feet) of vertical depth, is best exploited using horizontal wells drilled under-balanced.

The average production in Desan for December 2008 was 3.7 mmcf/d natural gas and 23 bbls/d of hydrocarbon liquid from a total of 27 producing wells. Desan production is 100% working interest. McDaniel assigned total proved reserves of 6.0 Bcf of natural gas and 24 mbbl of NGL to the Desan property as of the December 31, 2008 effective date.

Enterra has acquired 45 square kilometres (17 square miles) of 3D seismic and 61 kilometres (38 miles) of trade 2D seismic. Based upon the Trust's technical assessment of the seismic, six locations in the Jean Marie and three locations in the Debolt formation are at a drill ready stage. The Trust is evaluating a multi-well drilling program during the 2009 and 2010 winter drilling season.

Western Alberta
In western Alberta, Enterra's properties range from deep, high-rate foothills sour gas wells in Ricinus to mid-depth oil wells at Clair.

Clair
The Clair property is located seven miles north of Grande Prairie, Alberta. The Trust's assets include a 100% working interest in 3,040 acres of land, 25 producing wells, seven water injection wells, and a profit sharing interest in an oil treating and blending facility. Gas is conserved and processed at the Encana Sexsmith gas plant, and the oil is delivered into the Pembina Peace Pipeline System. Production is primarily from the Doe Creek (Dunvegan) formation with a small amount of gas production from the Charlie Lake formation. Production is light oil with a 41°API gravity, along with solution gas. This pool is under water flood to maximize oil recovery. There is also gas production from one Charlie Lake well. Average working interest production for December 2008 was 426 bbl/d of oil and 489 mcf/d of raw gas. Enterra's technical team is presently evaluating waterflood optimization options and step-out drilling opportunities for 2009 or 2010. McDaniel assigned total proved reserves of 308 mbbl of crude oil, 591 Mmcf of natural gas, and 31 mbbl of NGL to the Clair property as of the December 31, 2008 effective date.

Ricinus
Ricinus is located in the Rocky Mountain foothills, 80 miles northwest of Calgary. At Ricinus, Enterra holds a 45% working interest in a 2,800m (9,200 feet deep) high-rate Leduc reef sour gas well that produces steady at 10 Mmcf/d and 15bbl/d of NGL. This well has the capability to produce at higher rates, but has been limited to maximize the reserve recovery. McDaniel assigned proved reserves of 5.2 Bcf of natural gas and 6 mbbl of NGLs to the producing well as of the December 31, 2008 effective date.

Eastern Alberta

Provost-Alliance-Wainwright, Alberta
The Provost-Alliance-Wainwright producing area is located near Provost, Alberta. Major areas are Alliance, Sounding Lake, Soapy Lake, Halkirk, Monitor, Provost and Wainwright. Enterra currently has 252 producing oil and gas wells in this area.

Production is obtained primarily from the Dina, Cummings and Belly River formations. Average working interest production for December 2008 was 1,153 bbl/d of oil and NGLs and 1.3 Mmcf/d of gas. In order to increase production and lower operating costs, the Trust continues to optimize well pumping systems and upgrade or consolidate oil batteries and water injection facilities to handle high volumes of produced fluid more efficiently. Solution gas is currently conserved at most of the oil batteries.

McDaniel assigned total proved reserves 919 mbbl of oil, 327 Mmcf of natural gas and 11 mbbl of NGLs in the Provost-Alliance-Wainwright area, as of the December 31, 2008 effective date.

While these pools are mature, detailed geologic and engineering studies have identified significant potential for increases in both production and reserves through more efficient secondary recovery and exploitation of bypassed pay zones. These studies are ongoing and will be utilized to identify 2009 and 2010 opportunities.

Princess

Princess is located 100 miles southeast of Calgary. The primary production is crude oil (27º API) from the Pekisko formation, a reefal carbonate. Much of Enterra’s land is covered by 3D seismic, and detailed geological and geophysical studies have outlined new development drilling opportunities which the Trust may drill during 2009 and 2010. In addition, significant potential lies in the Glauconite and Sunburst formations. At year end 2008, Enterra had 23 producing wells in the Princess area with average working interest production of 390 bbl/d of crude oil and NGL and 655 mcf/d of natural gas.

McDaniel assigned total proved reserves in the Princess area of 289 mbbl of crude oil, 535 Mmcf of natural gas and 8 mbbl of NGLs in the Princess area as of December 31, 2008 effective date.

Saskatchewan

Enterra’s assets in west central Saskatchewan include several areas including Primate and Liebenthal. In addition, there are several minor non-core areas scattered geographically. In late 2008 Enterra shot a large 3D seismic program in the Cactus area. This 3D is currently being studied to pinpoint drilling locations for 2009. McDaniel assigned total proved plus probable reserves of 12.6 Bcf of natural gas and 1,056 mbbl of oil in the Saskatchewan properties as of the December 31, 2008 effective date.

Primate

The Primate area was the main producing asset of the Trigger Resources acquisition made by Enterra in 2007, and Enterra holds a 100% working interest in this property. Production is primarily from the McLaren and Colony formations. Although the oil is 11° API gravity, its gasified nature allows high initial production rates of up to 250 bbls/day per well of oil under primary recovery.

Average December 2008 production from the Primate area was 793 bbls/day of crude oil and 1,151 mcf/day of natural gas.

Plans for 2009 or 2010 include completing a study of secondary recovery opportunities in the main primate oil pool which potentially could potentially double the ultimate recoverable oil reserves. Plans also may include drilling several infill wells.

Liebenthal

The gas production from the Liebenthal area comes from the Viking formation. Enterra holds a 100% working interest in two prolific wells in the pool. Seismic indicates that the pool is structurally controlled, and future opportunities include infill drilling of the main pool and exploiting up-hole potential in the Belly River formation. Average December 2008 production from the Liebenthal area was 3,520 mcf/day of natural gas.

Cactus Lake

3D seismic was shot over Cactus area in late 2008. The seismic information continues to be studied, and plans for 2009 or 2010 include drilling several seismic delineated locations as well as farming in on adjacent lands.

Oklahoma

In Oklahoma the key producing horizon is the Hunton formation. The Hunton is a carbonate rock formation which has been largely ignored by the industry in areas with high water/hydrocarbon production ratios. Over the last decade, new drilling and production techniques have enabled profitable development of the Hunton formation. Extensive dewatering lowers reservoir pressure allowing the liberation and mobilization of oil and gas from smaller rock pores.

Peak hydrocarbon production rates average 150 BOE/d per horizontal well. Peak rates are generally observed within six months of production commencement. Enterra generally has a 20-25% working interest in producing wells drilled by the Trust's U.S. Farmout Partner. Average gross proved plus probable reserves are approximately 280 Mboe per horizontal well.

Under a farmout agreement, the U.S. Farmout Partner pays 100% of the costs to drill and complete each well on Trust lands to earn a 70% working interest. The farmout agreement requires the U.S. Farmout Partner to drill not less than 30 wells during rolling twenty-month periods. By the end of 2008, 61 wells were drilled as producers, in addition to three salt water disposal wells. Of the wells drilled by the end of 2008, 55 were producing wells, three are awaiting completion, one is completed but not producing and two were dry and abandoned. Enterra pays 100% of the costs of drilling the required water disposal wells and associated infrastructure, but recovers 100% of those costs plus interest over a 3-year period through a capital recovery agreement with the U.S. Farmout Partner.

Average production for 2008 in Oklahoma was 24.6 Mmcf/d of natural gas and 545 bbl/d of crude oil and NGLs. Haas attributed total proved reserves of 967 mbbl of crude oil, 3,955 mbbl of NGL's and 33.7 Bcf of natural gas to Oklahoma as of the January 1, 2009 effective date. Working interest production rates in December 2008 were 22.5 Mmcf/d and 547 bbl/d oil and NGL. Operating costs on these properties averaged $11.42/boe (Cdn $) during 2008. Enterra's U.S. office is located in Oklahoma City, with a fully staffed field office maintained in Carney, Oklahoma, about 50 miles to the north-east. The Trust's U.S. based staff as of December 31, 2008 numbers 53 people.

In Oklahoma, there is approximately 44,706 net undeveloped acres of land, with an average working interest of 100% at year end 2008. This acreage is centered in Alfalfa, Grant, Lincoln and Logan Counties. To date, more than 50 additional drilling locations on these properties have been identified.

Reserves Summary

See Note 22 to the Consolidated Financial Statement for information on Enterra's oil and gas producing activities.

Production before royalties from 2006 – 2008

	2008	2007	2006
Oil and NGLs (bbls/day)	3,756	4,698	5,126
Natural gas (mcf/day)	39,163	46,378	43,358
Total (boe/day)	10,283	12,428	12,352

Oil and Gas Wells

The following table summarizes the Trust's interest as at December 31, 2008 in wells that are producing and non-producing:

	Producing				Non-Producing					
	Oil		Gas		Oil		Gas		Grand Total	
State/Province	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	300.0	218.7	46.0	30.6	230.0	182.9	34.0	21.0	610.0	453.2
British Columbia	-	-	27.0	27.0	-	-	13.0	13.0	40.0	40.0
Saskatchewan	19.0	17.1	13.0	13.0	8.0	7.2	9.0	9.0	49.0	46.3
Total	319.0	235.8	86.0	70.6	238.0	190.1	56.0	43.0	699.0	539.5
Oklahoma	-	-	154.0	91.5	-	-	49.0	36.4	203.0	127.8

Grand Total	319.0	235.8	240.0	162.0	238.0	190.1	105.0	79.4	902.0	667.3

- Note this table does not include service/disposal wells.

Land Holdings

The following table summarizes land holdings in which Enterra has an interest at December 31, 2008.

Area	Gross Acres	Net Acres
Canada	275,389	177,905
United States	108,106	77,209
Total	383,495	255,114

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 able to meet any significant delivery commitments.

Environmental Issues

See Item 4. Business Overview, Government Regulations for a discussion on Enterra's Environmental Issues.

Plans for Expansion

As an oil and gas producer, Enterra has a declining asset base and therefore relies on development activities and acquisitions to replace production and add additional reserves. The Trust's future oil and natural gas production is highly dependent on Enterra's success in exploiting its asset base and acquiring or developing additional reserves. Although the Trust has an internal inventory of drilling opportunities it continues to exploit, Enterra will evaluate alternatives external to this inventory but will also evaluate and act on accretive external acquisition opportunities. An expansion will be financed through cash flow, debt financing, farm in agreements or other corporate financings.

ITEM 4A. UNRESOLVED STAFF COMMENTS

None

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" or "Enterra") contained in this Form 20-F. All amounts are stated in Canadian dollars and are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except where otherwise indicated. Discussion with regard to the Trust's 2009 outlook is based on currently available information.

A. Operating Results

Critical Accounting Estimates

Enterra prepares its financial statements and the accompanying notes in conformity with generally accepted accounting principles in Canada, which requires management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. Enterra identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of Enterra's financial condition, results of operations or liquidity and the degree of difficulty, subjectivity and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of Enterra's most critical accounting policies:

Reserve Estimates

Enterra's estimate of proved reserves is based on the quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, Enterra must estimate the amount and timing of future operating costs, royalties, development costs and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Trust's reserves. As such, Enterra's reserve engineers review and revise the Trust's reserve estimates at least annually.

Despite the inherent imprecision in these engineering estimates, Enterra's reserves are used throughout our financial statements. For example, since Enterra uses the units-of-production method to amortize its oil and gas properties, the quantity of reserves could significantly impact its DD&A expense. Enterra's oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of its proved reserves. Finally, these reserves are the basis for its supplemental oil and gas disclosures.

Asset Retirement Obligation (ARO)

The Trust has significant obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Enterra's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future, and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO is recorded at fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Income Taxes

Enterra's oil and gas exploration and production operations are currently located in Canada and the United States. As a result, Enterra is subject to taxation on its income in two jurisdictions. Enterra records future tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in its financial statements and tax returns. The Trust routinely assesses the ability to realize its future tax assets. If Enterra concludes that it is more likely than not that some portion or all of the future tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. Enterra considers future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

The Trust regularly assesses and, if required, establishes accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions in countries where the Trust operates. Tax reserves have been established and include any related interest, despite the belief by the Trust that certain tax positions have been fully documented in the Trust's tax returns. These reserves are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, case law and any new legislation. The Trust believes that the reserves established are adequate in relation to the potential for any additional tax assessments.

SALES VOLUMES BEFORE ROYALTIES

	2008	2007	2006
Daily sales volumes – average			
Oil & NGL (bbls per day)	3,756	4,698	5,126
Natural gas (mcf per day)	39,163	46,378	43,358
Total (boe per day)	10,283	12,428	12,352
Daily sales volumes – exit rate			
Oil & NGL (bbls per day)	4,250	3,952	4,758
Natural gas (mcf per day)	33,321	45,031	46,105
Total (boe per day)	9,804	11,457	12,442

Sales volumes mix by product			
Oil & NGL	37%	38%	41%
Natural gas	63%	62%	59%
	100%	100%	100%

2008 compared to 2007

Average production for 2008 decreased 17% to 10,283 boe per day from 12,428 boe per day in 2007. The decline in average production was due primarily to the sale of properties which closed during the first half of the year.

Average production during 2008 consisted of 3,756 bbls per day of oil and natural gas liquids ("NGL") and 39,163 mcf per day of natural gas, resulting in a mix of 37% oil and NGL and 63% natural gas. Enterra exited 2008 with production of 9,804 boe per day. As a result of renegotiated marketing contracts for a portion of the U.S. natural gas production under which Enterra receives a direct portion of the natural gas liquids extracted from the gas stream, the 2009 production mix is expected to be about 47% oil and natural gas liquids and 53% natural gas.

In 2008, Enterra participated in the drilling of 42 (17.4 net) wells; 11 (9.8 net) wells in Canada and 31 (7.6 net) wells in Oklahoma. All wells, except the salt water disposal well, in Oklahoma were drilled by a joint venture partner under an area farmout agreement that resulted in the joint venture partner paying 100% of the drilling and completion costs in exchange for 70% working interest. Overall, the drilling in Canada and Oklahoma resulted in 31 (8.7 net) gas wells, 8 (7.2 net) oil wells, 1 (1.0 net) salt water disposal well and two (0.5 net) wells drilled and abandoned, resulting in a success rate of 97%.

2007 compared to 2006

Average production for 2007 increased 1% to 12,428 boe/day from 12,352 boe/day in 2006. Positive contributions to production during 2007 include the acquisition of Trigger Resources in Q2 2007, start-up of a prolific Leduc well at Ricinus in late 2006, and production additions associated with our drilling programs in Oklahoma and Canada. Offsetting these additions were natural declines, weather-related disruptions in Oklahoma due to record rainfalls for the year and a severe ice storm in December, drilling and production difficulties at our Primate field, and operational delays in tying in certain wells in Oklahoma due to equipment shortages.

Average production during 2007 consisted of 4,698 bbls/day of oil and natural gas liquids ("NGL") and 46,378 mcf/day of natural gas, resulting in a mix of 38% oil and NGL and 62% natural gas. At December 31, 2007 the Trust had an exit production rate of 11,457 boe/day.

In 2007, the Trust participated in the drilling of 32 (11.8 net) wells; 13 (7.5 net) in Canada and 19 (4.3 net) in Oklahoma. All wells in Oklahoma were drilled by a joint venture partner under an area farmout agreement that resulted in the joint venture partner paying 100% of the drilling and completion costs in exchange for 70% working interest. Overall, the drilling in Canada and Oklahoma resulted in 23 (5.4 net) gas wells, 8 (5.4 net) oil wells and one well (1.0 net) that was drilled and abandoned, resulting in a success rate of 97%.

COMMODITY PRICING

Pricing Benchmarks

	2008	2007	2006
WTI (US$ per bbl)	99.65	72.34	66.22
Average exchange rate: US$ to Cdn$1.00	0.94	0.93	0.88
WTI (Cdn$ per bbl)	106.62	77.78	75.25
AECO daily index (Cdn$ per GJ)	7.71	6.55	6.53
NYMEX (US$ per mmbtu)	8.93	6.92	7.26

West Texas Intermediate ("WTI") is a standard benchmark for the price of oil and is expressed in U.S. dollars per barrel. The price of natural gas in the United States is benchmarked on the New York Mercantile Exchange ("NYMEX") and expressed in U.S. dollars per million British Thermal Units ("mmbtu"). In Western Canada the benchmark is the price at the AECO hub (a storage and pricing hub for Canadian natural gas market) and is priced in Canadian dollars per gigajoule ("GJ"). For the purposes of financial reporting, Enterra expresses its realized prices for oil and gas in Canadian dollars.

The price that is received for a majority of the Trust's oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that is received 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. The Trust could be subject to unfavourable price changes to the extent that the Trust has engaged, or in the future engages, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

2008 compared to 2007
Benchmark oil prices for 2008 increased 38% to an average of US$99.65 per bbl WTI from US$72.34 per bbl WTI in 2007. The U.S. dollar exchange rate to the Canadian dollar stayed relatively consistent at an average of US$0.94 per Canadian dollar during 2008 compared to US$0.93 per Canadian dollar during 2007.

Benchmark natural gas prices for 2008 on the NYMEX increased to an average of US$8.93 per mmbtu from US$6.92 per mmbtu in 2007. In Canada, AECO pricing was significantly higher than 2007 levels, averaging $7.71 per GJ during 2008 compared to $6.55 during 2007.

2007 compared to 2006
Benchmark oil prices for 2007 increased 9% to an average of US$72.34 per bbl WTI from US$66.22 per bbl WTI in 2006. The effect of the increase was off-set by a 6% year over year weakening of the U.S. dollar against the Canadian dollar, with the exchange rate rising to an average of US$0.93 per Canadian dollar in 2007 from an average of US$0.88 in 2006.

Benchmark natural gas prices for 2007 on the NYMEX decreased US$0.34/mmbtu or 5%, from 2006, averaging US$6.92/mmbtu in 2007. In Canada, AECO pricing was consistent with 2006 levels, averaging $6.55/GJ.

Average Commodity Prices Received

	2008	2007	2006
Oil (1) (Cdn$ per bbl)	91.55	61.84	62.54
Natural gas (Cdn$ per mcf)	8.94	6.60	6.70
Oil commodity contract settlements (Cdn$ per bbl)	0.50	(0.75)	(0.41)
Natural gas commodity contract settlements (Cdn$ per mcf)	0.04	0.44	0.83
Combined oil (1) (Cdn$ per bbl)	92.05	61.09	62.13
Combined natural gas (Cdn$ per mcf)	8.98	7.04	7.53
Total (2) (Cdn$ per boe)	67.83	49.34	51.82

(1) Includes NGL and sulphur revenue.
(2) Price received excludes unrealized mark-to-market gain or loss.

2008 compared to 2007
The 2008 average price received for oil by Enterra, net of commodity contract settlements increased 51% to $92.05 per bbl from $61.09 per bbl in 2007. The 2008 average price received for natural gas, net of commodity contract settlements, was up 28% to $8.98 per mcf from $7.04 per mcf in 2007.

2007 compared to 2006
The 2007 average price received for oil by Enterra, net of hedge settlements, was down 2% to $61.09/bbl from $62.13/bbl in 2006. The 2007 average price received for natural gas, net of hedge settlements, was down 7% to $7.04/mcf from $7.53/mcf in 2006.

REVENUES

Revenues (in thousands of Canadian dollars except for percentages)

	2008	2007	2006
Oil and NGL	126,557	104,753	114,669
Natural gas	128,711	119,075	119,111
Revenue before mark-to-market adjustments (1)	255,268	223,828	233,780
Unrealized mark-to-market gain (loss) on commodity contracts	20,229	(16,792)	10,628
Oil and natural gas revenues	275,497	207,036	244,408

(1) Non–GAAP measure.

2008 compared to 2007

Natural gas revenue for 2008 increased 8% from 2007 to $128.7 million which was the result of a 35% increase in the sales price of natural gas received for 2008 offset by production volumes for 2008 decreasing by 16%. For oil and NGL, the 21% revenue increase from 2007 to $126.6 million was the result of the increase in oil price received of 48% which was offset by a 20% decrease in production volumes from 2007. The increase in revenue was significantly higher than expected due to the unrealized mark-to-market gain on commodity contracts of $20.2 million during 2008. Unrealized mark-to-market on commodity contracts increased to $20.2 million for the year compared to a loss of $16.8 million in the prior year.

2007 compared to 2006
Natural gas revenue for 2007 was consistent with 2006 at $119.1 million. Natural gas production volumes for 2007 increased by 1%; however this was offset by a 7% decrease in the sales price of natural gas received for 2007. For oil and NGL, the 9% revenue decrease from 2006 was consistent with an 8% decrease in production volumes from 2006, while the oil price received decreased slightly. Overall, in 2007 revenues decreased by $37.4 million or 15% compared to 2006 with much of the decrease attributable to rising oil prices that resulted in an unrealized mark-to-market loss of $16.8 million at year-end compared to a mark-to-market gain at the end of 2006 of $10.6 million.

COMMODITY CONTRACTS

The Trust has a formal risk management policy which permits management to use specified price risk management strategies for up to 50% of its projected gross crude oil, natural gas and NGL production including fixed price contracts, costless collars and the purchase of floor price options and other derivative instruments to reduce the impact of price volatility and ensure minimum prices for a maximum of 24 months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this the Trust seeks to provide a measure of stability and predictability of cash inflows.

Enterra has recently been focusing its price risk management on purchasing floor price options to better maximize its exposure to upside price movements while trying to ensure sufficient cash flow to achieve its budgeted plans. As of December 31, 2008, less than one quarter of the oil and gas production of Enterra is economically hedged with commodity contracts that limit the maximum price for these commodities. For the winter heating season beginning November 1, 2008 and ending March 31, 2009, only commodity floor price contracts will remain on a portion of Enterra gas production.

The mark-to-market value of the commodity contracts is determined based on the quoted market price as at December 31 that was obtained from the counterparty to the economic hedge. Enterra then evaluates the reasonability of this price in comparison to the value of other commodity contracts it currently owns as well as recently quoted prices received from other counterparties for various commodity contracts. The Trust deals with several counterparties to diversify the risks associated with having all commodity contracts with only one counterparty. The credit worthiness of each counterparty is assessed at the time of purchase of each financial instrument and is regularly assessed based on any new information regarding the counterparty. The current commodity contracts held by Enterra all mature during 2009 and based on Enterra's assessment the counterparties are believed to be creditworthy.

At December 31, 2008, the following financial derivatives and fixed price contracts were outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Floor	Gas	8.00 ($/GJ)	3,000 GJ	November 1, 2008 – March 31, 2009
Floor	Gas	9.00 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	9.50 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	10.00 (US$/mmbtu)	5,000 mmbtu	

				November 1, 2008 – March 31, 2009
Floor	Oil	72.00 (US$/bbl)	1,000 bbl	January 1, 2009 – December 31, 2009
Sold Call	Oil	91.50 (US$/bbl)	500 bbl	July 1, 2009 – December 31, 2009

Enterra had the following physical contracts outstanding as at December 31, 2008:

Fixed purchase	Power (Alberta)	62.90 (Cdn$/Mwh)	72 Mwh	July 1, 2007 – December 31, 2009

As at December 31, 2008 the above commodity contracts had a net mark-to-market asset position of $14.3 million which is a difference of $15.6 million from the Q3 2008 net liability of $1.3 million. This change relates primarily to the significant drop in oil prices which decreased from the US$100.00 range at the end of Q3 2008 to the US$44.00 range at the end of 2008 and does not necessarily reflect the expected future cash settlement value of these contracts.

Since December 31, 2008, the following financial derivatives and fixed price contracts were entered into:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Fixed	Gas	5.01 (US$/mmbtu)	3,000 mmbtu	April 1, 2009 – October 31, 2009
Fixed	Gas	5.015 ($/GJ)	2,000 GJ	April 1, 2009 – October 31, 2009
Fixed Basis Differential (1)	Gas	Differential Fixed @ $1.08 US$/mmbtu	3,000 mmbtu	April 1, 2009 – October 31, 2009
Fixed Basis Differential (1)	Gas	Differential Fixed @ $1.10 US$/mmbtu	3,000 mmbtu	April 1, 2009 – December 31, 2009
Fixed	Gas	4.50 ($/GJ)	2,000 GJ	April 1, 2009 – December 31, 2009
Fixed	Gas	4.6725 (US$/mmbtu)	3,000 mmbtu	April 1, 2009 – December 31, 2009
Fixed	Gas	6.25 (US$/mmbtu)	5,000 mmbtu	November 1, 2009 – December 31, 2010
Fixed Basis Differential (1)	Gas	Differential Fixed @ $0.615 US$/mmbtu	5,000 mmbtu	November 1, 2009 – December 31, 2010
Fixed	Oil	50.00 (US$/bbl)	250 bbl	April 1, 2009 –June 30, 2009
Fixed	Oil	50.35 (US$/bbl)	200 bbl	July 1, 2009 – September 30, 2009
Fixed	Oil	65.00 ($/bbl)	300 bbl	July 1, 2009 – September 30, 2009
Fixed	Oil	85.00 ($/bbl)	500 bbl	October 1, 2009 – December 31, 2010

(1) NYMEX / Southern Star (Oklahoma) 2009 basis differential.

ROYALTIES

Royalties include crown, freehold and overriding royalties, production taxes and wellhead taxes. Royalties vary depending on the jurisdiction, volumes that are produced, total volumes sold and the price received for the sales.

Royalties (in thousands of Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
Royalties	58,350	45,365	48,288
As a percentage of revenues	23%	20%	21%
Royalties per boe ($)	15.50	10.00	10.71

In late October 2007, the Alberta provincial government announced a new oil and gas royalty regime to take effect January 1, 2009. The Trust has assessed the impact of the new royalty regime and has determined that it will have a modest negative effect on its current portfolio of production and reserves in Alberta. Enterra now incorporates the new royalty scheme into its Alberta-based economic analysis prior to pursuing opportunities in the province. During 2008, approximately 31% of the Trust's production came from Alberta.

2008 compared to 2007

Royalties in 2008 increased 29% to $58.4 million from $45.4 million in 2007 primarily as a result of the higher prices received for oil and natural gas during the course of 2008. As a percentage of revenue before mark-to-market adjustments, royalties were 23% for 2008 and 20% for 2007.

2007 compared to 2006

Royalties in 2007 decreased compared to 2006 as a result of royalty rebates realized in the U.S. The U.S. operations applied for, and received, a royalty rebate for its horizontal wells in the state of Oklahoma. Enterra realized rebates of $3.2 million in 2007 for royalties paid in 2006 and 2007.

PRODUCTION EXPENSE

Production Expense (in thousands Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
Production expense	55,846	62,483	48,494
Non-cash gain (loss) from power contracts	(157)	(447)	-
Cash production costs	55,689	62,036	48,494
Production expense per boe ($)	14.84	13.77	10.76
Non-cash gain (loss) from power contracts per boe ($)	(0.04)	0.10	-
Cash production costs per boe ($)	14.80	13.67	10.76

2008 compared to 2007

In 2008, cash production costs increased 8% to $14.80 per boe compared to $13.67 per boe in 2007 primarily due to properties with low operating costs being sold in the first half of 2008 and to operating expenses increasing during 2008 throughout the industry as a whole. Production costs for 2008 were also slightly higher due to additional maintenance and well workovers. With high commodity prices during the summer, additional work was performed to bring on more production which resulted in higher operating costs but the associated production did generate positive cash flow.

2007 compared to 2006

In 2007, cash production costs increased 28% to $13.67 per boe compared to $10.76 per boe in 2006 primarily due to Canadian operations experiencing one time non-recurring expenses related to regulatory compliance, increased well workover costs, and repair and environmental expenses associated with three pipeline failures in Canada. Severe weather conditions increased costs and reduced production in Oklahoma as record spring and summer rain, were followed by a destructive ice storm in December.

TRANSPORTATION EXPENSE

Transportation expense is a function of the point of legal transfer of the product and is dependent upon where the product is sold, production split, location of properties as well as industry transportation rates that are driven by supply and demand of available transport capacity.

Transportation Expense (in thousands of Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
Transportation expense	2,492	2,340	1,867
Transportation expense per boe ($)	0.66	0.52	0.41

2008 compared to 2007

On a year to date basis, transportation costs increased 27% to $0.66 per boe for the year ended December 31, 2008 compared to $0.52 per boe for the same period in 2007. Transportation expense increased 6% primarily due to the overall increase in costs in the industry. As well, the per boe equivalent cost have increased due in part to the sale of certain lower operating cost properties in Q1 2008 as part of the asset disposition program.

2007 compared to 2006

On a year to date basis, transportation costs increased 27% to $0.52 per boe for the year ended December 31, 2007 compared to $0.41 per boe for the same period in 2006. Transportation expense increased 25% primarily due to the overall increase in costs in the industry.

GENERAL AND ADMINISTRATIVE EXPENSE

General and Administrative Expense (in thousands of Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
G&A expense	15,858	20,414	17,145
G&A expense per boe ($)	4.21	4.50	3.80

2008 compared to 2007
General and administrative expense ("G&A") decreased by 22% in 2008 compared to 2007 on a total dollar basis but stayed relatively flat on a per boe basis due to lower production volumes, as a result of the asset sales in Q1 and Q2 2008, when compared to 2007. For 2008, G&A costs were $4.21 per boe compared to $4.50 per boe for 2007, a 6% decrease primarily due to implementing cost reduction plans.

2007 compared to 2006
General and administrative expenses increased 19% in 2007 to $20.4 million from $17.1 million in 2006. G&A per boe increased by 18% to $4.50 per boe in 2007 compared to $3.80 per boe in 2006. The increase in general and administrative costs related primarily to an increase in personnel in 2007 from 2006 and increased consulting costs in Q3 and Q4 2007 related to the turnover of management and employees.

PROVISION FOR NON-RECOVERABLE RECEIVABLES

The provision for non-recoverable receivables was $8.5 million for 2008 as compared to $nil at December 31, 2007 and 2006. On July 22, 2008, SemGroup, a midstream and marketing company through which the Trust marketed a portion of the Trust's production, filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. and the Canadian units of SemGroup filed for protection under the Companies' Creditors Arrangement Act. As a result, the Trust has recorded a provision for non-recoverable receivables for the full amount owed by SemGroup a one time charge of $8.5 million with a corresponding decrease to net income ($6.0 million net of tax). Management believes that a portion of the $8.5 million is recoverable; however, it is indeterminable at this time, therefore, an allowance has been recorded for the amount.

INTEREST EXPENSE

Interest expense for 2008 was $17.5 million which was comprised of interest on bank indebtedness of $8.4 million and interest on convertible debentures of $11.5 million less interest income of $2.4 million.

Interest Expense (in thousands of Canadian except for percentages and per boe amounts)

	2008	2007	2006
Cash interest expense on bank indebtedness, capital lease, and note payable	7,814	12,120	14,185
Cash interest expense on convertible debentures	9,726	8,625	786
Cash interest income	(2,350)	(489)	-
Subtotal cash interest expense	15,190	20,256	14,971
Non-cash interest expense on bank indebtedness, capital lease, and note payable	548	988	11,713
Non-cash interest expense on convertible debentures	1,728	1,338	33
Total interest expense	17,466	22,582	26,717
Cash interest expense per boe on bank indebtedness, capital lease, and note payable ($)	2.08	2.67	3.15
Cash interest expense per boe on convertible debentures ($)	2.58	1.90	0.17
Cash interest income per boe ($)	(0.62)	(0.11)	-
Total cash interest expense per boe ($)	4.04	4.46	3.32

2008 compared to 2007
Interest expense during 2008 on bank indebtedness decreased to $8.4 million compared to $13.1 million in 2007 due to lower debt levels, declining Bank of Canada interest rates and lower interest rates that were negotiated under the June 25, 2008 revised credit facility agreement. Enterra ended 2008 with a bank indebtedness balance of $95.5

million compared to $172.0 million at the start of 2008.

The interest expense on convertible debentures for 2008 increased to $11.5 million compared to $10.0 million in 2007. This increase of 15% is due to the 8.25% convertible debentures issued on April 28, 2007 of $40.0 million being outstanding for the entire year of 2008 compared to only part of 2007.

2007 compared to 2006

Interest expense during 2007 on bank indebtedness decreased to $13.1 million compared to $25.9 million in 2006 due to lower debt levels and lower interest rates. Enterra ended 2007 with a bank indebtedness balance of $172.0 million compared to $188.2 million at the start of 2007.

The interest expense on convertible debentures for 2007 increased to $10.0 million compared to $0.8 million in 2006. This increase is due to the 8.25% convertible debentures issued on April 28, 2007 of $40.0 million and the 8.00% convertible debentures issued on November 21, 2006 of $138.0 million.

UNIT-BASED COMPENSATION EXPENSE

Unit-Based Compensation Expense (in thousands Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
Gross unit-based compensation expense	4,819	4,128	3,229
Capitalized	(404)	-	-
Unit-based compensation expense	4,415	4,128	3,229
Unit-based compensation expense per boe ($)	1.17	0.91	0.72

2008 compared to 2007
Non-cash unit-based compensation expense for 2008 was $4.4 million compared to $4.1 million in 2007 due to an increase in restricted units and trust unit options issued.

2007 compared to 2006
Non-cash unit-based compensation expense for 2007 was $4.1 million compared to $3.2 million in 2006 due to an increase in restricted units and trust unit options issued.

DEPLETION, DEPRECIATION AND ACCRETION (“DD&A”)

Depletion, Depreciation and Accretion (in thousands of Canadian dollars except for percentages and per boe amounts)

	2008	2007	2006
DD&A – excluding impairment	99,377	124,447	135,429
Impairment expense	-	26,254	66,019
DD&A	99,377	150,701	201,448
DD&A per boe – excluding impairment ($)	26.40	27.43	30.04
Impairment expense per boe ($)	-	5.79	14.64
DD&A per boe ($)	26.40	33.22	44.68

2008 compared to 2007
DD&A expenses excluding impairment decreased by 20% in 2008 to $99.4 million compared to $124.4 million in 2007. DD&A expenses excluding impairment on a boe basis decreased by 4% from $27.43 per boe in 2007 to $26.40 in 2008. The decrease year over year is caused by reduced property, plant and equipment values primarily as a result of asset dispositions in the first half of 2008.

2007 compared to 2008
DD&A expenses excluding impairment decreased by 8% in 2007 to $124.4 million compared to $135.4 million in 2006. DD&A expenses excluding impairment on a boe basis decreased by 9% from $30.04 per boe in 2006 to $27.43 in 2007. The decrease year over year is caused by reduced property, plant and equipment values primarily as a result of the impairment in 2006 and 2007.

Ceiling Test

Under Canadian GAAP, a ceiling test is applied to the carrying value of the property, plant and equipment and other assets. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties, and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties, and the cost of major development projects. When required the cash flows are estimated using expected future product prices and costs which are discounted using a risk-free interest rate.

Enterra completed ceiling test calculations for the Canadian and U.S. cost centers as at December 31, 2008 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The ceiling test did not result in a write down of the Canadian cost center or the U.S. cost center.

GOODWILL IMPAIRMENT

2008 compared to 2007

A goodwill impairment charge was not recorded in 2008 compared to a $76.5 million charge in 2007. During 2007 the balance of goodwill in the Canadian reporting unit was considered impaired. No goodwill remained at December 31, 2008 and 2007.

2007 compared to 2006

A goodwill impairment charge of $76.5 million was recorded in 2007 and no goodwill impairment charge was recorded in 2006. During 2007 the balance of goodwill in the Canadian reporting unit was considered impaired. No goodwill remained at December 31, 2007 and there was a balance of $76.3 million at December 31, 2006.

FOREIGN EXCHANGE

2008 compared to 2007

Foreign exchange for the year ended December 31, 2008 was a loss of $1.3 million compared to a loss of $0.5 million in 2007. The foreign exchange loss for 2008 is comprised of a realized loss of $2.1 million as a result of the application of the current rate method on the U.S. operations and a gain of $0.8 million as a result of the weakening of the Canadian dollar against the U.S. dollar in the latter half of 2008.

2007 compared to 2006

Foreign exchange for the year ended December 31, 2007 was a loss of $0.5 million compared to a loss of $1.9 million in 2006. The foreign exchange loss for 2007 is comprised of a realized loss of $2.1 million as a result of the application of the current rate method on the U.S. operations and a gain of $1.6 million as a result of selling of U.S. funds transferred from Enterra’s U.S. subsidiary into Canadian dollars.

The foreign exchange sensitivity in note 13 of the 2008 financial statements indicates that for every $0.02 cent weakening of the Canadian dollar relative to the U.S. dollar, the benefit to the Trust is $0.4 million in 2008 pre-tax income; therefore, the weakening of the Canadian dollar relative to the U.S. dollar has had a positive impact on the Trust.

TAXES

2008 compared to 2007

Future income tax for the year ended December 31, 2008 was $4.5 million compared to a future income tax reduction of $36.1 million in 2007. The federal and provincial statutory rate was 29.7% at December 31, 2008 compared to an effective tax rate of 37.7% and a tax rate applied to temporary differences of 25.0%. The primary reason for the variance in the effective tax rate and the statutory tax rate is the result of items not deductible for tax in the U.S. operations in 2008 which should be deductible beginning in 2010 when the withholding tax on U.S. source interest income will become zero, compared to the current 5% rate, the non-deductible stock base compensation, and the difference between the U.S. and Canadian tax rates.

2007 compared to 2006

Future income tax reduction of $36.1 million arose mainly due to the reduction in book basis due to the impairment on property, plant and equipment in 2007. The increase in non-capital losses gave rise to $4.9 million in future income tax reduction. Depletion expense, which accounts for impairment of property, plant and equipment accounted for another $31.5 million. The reduction in 2006 of $58.9 million is higher than in 2007 due to the adjustment in tax rate from 34.5% in 2005 to 32.1% giving rise to an income tax reduction of $6.7 million in 2006.

In determining its taxable income, Enterra Energy Corp. ("the Corporation"), a wholly owned subsidiary of the Trust deducts interest payments made to the Trust, effectively transferring the income tax liability to unitholders thus reducing the Corporation's taxable income to nil. Under the Corporation's policy, at the discretion of the board of directors, funds can be withheld from distributions to fund future capital expenditures, repay debt or other purposes. In the event withholdings increase sufficiently, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through various options including the issuance of additional trust units, increased tax pools from additional capital spending, modifications to the distribution policy or potential changes to the corporate structure. The corporate subsidiaries of the Trust are subject to tax if deductions are inadequate to reduce taxable income to zero.

On October 31, 2006 the Canadian Minister of Finance announced certain changes to the taxation of publicly traded trusts ("Bill C-52"). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. Bill C-52 applies to a specified investment flow-through ("SIFT") trust and will apply a tax at the trust level on distributions of certain income from such SIFT trusts at a rate of tax comparable to the combined federal and provincial corporate tax rate. These distributions will be treated as dividends to the trust unitholders. The Trust constitutes a SIFT and as a result, the Trust and its unitholders will be subject to Bill C-52.

Bill C-52 commenced January 1, 2007 for all SIFT's that began to be publicly traded after October 31, 2006 and commencing January 1, 2011 for all SIFT's that were publicly traded on or before October 31, 2006. It is expected that the Trust will not be subject to the taxation requirements of Bill C-52 until January 1, 2011.

Commencing January 1, 2011, the Trust will not be able to deduct certain of its distributed income. The Trust will become subject to a distribution tax ranging from 25 to 28 percent but this tax will not apply to returns of capital. Enterra will consider the options and alternative structures with legal and business advisors to determine if any potential restructuring available to maximize value is in the best interest of unitholders.

The federal component of the proposed tax on SIFT is expected to be 15 percent in 2012 (25 to 28 percent in total including provincial income taxes) and thereafter. The Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust. In 2008, no reduction of the future income tax liability was recorded for temporary differences (2007 – $9.9 million). Subsequent to 2007, the Trust suspended its distributions which caused these temporary differences to no longer meet the criteria for future income tax asset recognition. Overall, there was no impact in 2008 due to the proposed tax on SIFT.

NET INCOME (LOSS)

2008 compared to 2007
Net income in 2008 was $7.1 million ($0.11 per trust unit) compared to a loss of $142.0 million (loss of $2.38 per trust unit) in 2007. The net income during the year is the result of increases in commodity prices in 2008, a reduction in general and administrative expenses and no impairment charges on goodwill or property, plant and equipment taken in 2008. The net income was partially offset by the $8.5 million charge relating to the provision for non-recoverable receivables owed by SemGroup.

2007 compared to 2006
Net loss in 2007 was $142.0 million (loss of $2.38 per trust unit) compared to a loss of $64.2 million (loss of $1.46 per trust unit) in 2006. The increase in the net loss during the year is the result of a $76.5 million impairment charge on goodwill taken in 2007.

NON-GAAP FINANCIAL MEASURES

Management uses certain key performance indicators ("KPIs") and industry bench marks such as cash flow netback, funds from operations, revenue before mark-to-market adjustment, working capital, net debt, operating netbacks and operating recycle ratio to analyze financial performance. Management feels that these KPIs and benchmarks are key measures of profitability and overall sustainability for the Trust. These KPIs and benchmarks as presented do not have any standardized meanings prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities. All of the measures have been calculated on a basis that is consistent with previous disclosures.

Cash Flow Netback

Management uses cash flow netback to analyze operating performance. Cash flow netback, as presented, is not intended to represent an alternative to net income (loss) or other measures of financial performance calculated in accordance with GAAP. All references to cash flow netback throughout this MD&A are based on the reconciliation in the table below:

Cash Flow Netback (in thousand of Canadian dollars, except for per unit and per boe amounts)

	2008	2007	2006
Net income (loss)	7,061	(142,036)	(64,239)
Future income taxes	4,487	(36,051)	(58,899)
Foreign exchange loss (gain)	1,279	951	1,038
Depletion, depreciation and accretion	99,377	150,701	201,448
Goodwill impairment	-	76,463	-
Non-cash interest expense	2,276	2,327	11,746
Financing fees	-	-	5,065
Amortization of marketing contract	-	-	(1,447)
Non-controlling interest	-	-	(36)
Loss on sale of assets	-	-	59
Unit based compensation expense	4,415	4,128	3,229
Unrealized mark-to-market (gain) loss on commodity contracts	(20,072)	16,205	(10,628)
Provision for non-recoverable receivables	8,522	-	-
Funds from operations	107,345	72,688	87,336
Total volume (mboe)	3,764	4,536	4,508
Cash flow netback per boe (non-GAAP) ($)	28.52	16.02	19.37

Funds from Operations

Management uses funds from operations to analyze operating performance and leverage. Funds from operations, as presented, is not intended to represent cash provided by operating activities nor should it be viewed as an alternative to cash provided by operating activities or other measures of financial performance calculated in accordance with GAAP. All references to funds from operations are based on cash provided by operating activities, before changes in non-cash working capital, as reconciled in the table below:

Funds from Operations (in thousands of Canadian dollars)

	2008	2007	2006
Cash provided by operating activities	91,560	76,844	64,485
Changes in non-cash working capital items	5,492	(6,381)	21,632
Asset retirement costs incurred	1,771	2,225	1,219
Provision for non-recoverable receivables	8,522	-	-
Funds from operations	107,345	72,688	87,336

2008 compared to 2007
In 2008, funds from operations increased by 48% over 2007. The increase in funds from operations is primarily the result of higher commodity prices realized.

2007 compared to 2006
In 2007, funds from operations decreased by 17% from 2006. The decrease in funds from operations is primarily the result of lower commodity prices realized, an increase in operating expenses and higher general and administrative expenses. These decreases were partially offset by lower interest expenses.

CAPITAL EXPENDITURES

The following table represents the capital expenditures that were paid for with cash.

Capital Expenditures (in thousands of Canadian dollars except for percentages)

	2008	2007	2006
Capital expenditures	32,891	88,323	30,918
Capital expenditures to be recovered (1)	19,976	6,724	-
Amounts recovered under agreement	(5,049)	(1,105)	-
Total	47,818	93,942	30,918

(1) Recovered under capital recovery agreement over 36 months after project completion.

During the year ended December 31, 2008 in Canada, Enterra spent $21.3 million in capital expenditures. The major components of these expenditures include: $11.8 million for wells drilled or currently being drilled, $2.1 million on well optimization and activation projects, $2.0 million on land and seismic acquisition, $1.0 million on the acquisition of gross overriding royalty rights in northeastern British Columbia, $2.2 million related to well, facility and other equipment maintenance and $2.2 million related to the capitalization of certain G&A costs identified as attributable to exploration and development activities.

During the year ended December 31, 2008 in the U.S., a total of $31.6 million was spent on capital expenditures. Enterra is involved in a farmout and capital recovery agreement whereby the Trust recovers infrastructure costs incurred from a joint venture partner. Infrastructure costs incurred in the U.S. under the capital recovery agreement were $20.0 million during 2008. These costs were billed to the joint venture partner as the projects had reached the necessary stage of completion and became recoverable over a three-year period as specified in the agreement.

Interest is charged on the outstanding balance at 12% per annum. Enterra received a total of $5.0 million of principal repayments and $1.7 million in interest from this capital recovery agreement during 2008.

The capital expenditures in the U.S. that Enterra is solely responsible for totalled $11.6 million, of which $10.8 million was spent on acquisitions of land for future development in Oklahoma. In addition, $0.8 million was incurred for other equipment.

The remaining costs incurred include $14.9 million for related infrastructure which will be billed to the joint venture partner under the terms of the agreement once the projects reach a certain stage of completion.

Enterra closed the dispositions of $39.6 million of non-core assets during 2008 with the net proceeds used to reduce debt.

On April 30, 2007, the Trust closed the acquisition of Trigger Resources. The results of operations of Trigger Resources are included in the consolidated financial statements as of April 30, 2007. Total consideration paid for Trigger Resources was $63.3 million (including transaction costs of $0.3 million).

Excluding the acquisition of Trigger Resources, during the year ended December 31, 2007 in Canada, the Trust spent $16.0 million in capital expenditures the major components of which include; $2.2 million on 3-D seismic in northeastern British Columbia to aid in the development of the proved and probable reserves, $6.9 million related to drilling and completions of which $2.2 million was related to the four wells drilled on the lands in Saskatchewan, $0.7 million for the construction of facilities and pipelines and $5.5 million for other plant and equipment. The Trust sold $11.3 million of non-core assets during the year.

During the year ended December 31, 2007 in the U.S., approximately $5.3 million of the $15.7 million capital expenditures in the U.S. operations was spent on acquisitions of land for future development in Oklahoma. In addition, $3.8 million was incurred on completion and equipping of two salt water disposal wells and $3.0 million on infrastructure additions to service the new wells being added by the strategic partner of the Trust. All of the expenditures were in support of new wells being drilled under the area farm-out agreement. An additional expenditure of $3.3 million (before adjustments) was spent for the acquisition of assets from a working interest owner in certain oil and gas properties located in Wyoming.

During 2007 in the U.S., costs totaling $4.0 million for a salt water disposal well and its related infrastructure were removed from property, plant and equipment and classified as a receivable. Under the agreement with the joint venture partner, Enterra will recover the costs of the infrastructure over a three-year period. During 2007, the Trust earned $0.4 million of interest revenue on the receivable under this arrangement.

Capital additions for the year ended December 31, 2006 were $420.0 million. In addition to the acquisition of the Oklahoma Assets of $353.0 million (of which $8.9 million was unpaid at December 31, 2006), the assets acquired through the JED swap, including post closing adjustments, of $32.4 million, property, plant and equipment additions of $30.9 million, $3.3 million of net asset retirement obligations and $0.4 million related to minority interest accounting as per EIC-151 were charged to property, plant and equipment. Total dispositions for the year ended December 31, 2006 were $50.8 million.

In 2006 in Canada, the Trust spent $15.5 million in capital expenditures; $4.5 million related to drilling and completions operations, $4.4 million for the construction of facilities and pipelines, $2.3 million for other plant and equipment and $1.6 million for the completion equipping and tie-in of the deep gas well at Ricinus.

In Oklahoma in 2006, the Trust initiated an aggressive land acquisition program. During the year approximately US$4.5 million was spent to acquire lands for future development. In addition, during Q4 2006 the Trust drilled two salt water disposal wells at a total cost of approximately US$4.8 million. On occasion and as required, the Trust will drill further water disposal wells and make additions to existing facilities to support the dewatering efforts of the new wells being drilled under the farmout. During 2006 the trust also spent approximately US$1.5 million for infrastructure additions to support the locations being drilled. The capital cost of the disposal wells and infrastructure additions is recovered by the Trust over a 3 year period once the partner begins to fully utilize the facilities.

Enterra accounts for its investment in its U.S. operations as a self-sustaining operation which means the capital assets associated with the U.S. operations (as well as all other balance sheet accounts for the U.S. operations) are subject to revaluation to the current exchange rate at each balance sheet date. The result of this revaluation is a change in the carrying value of the U.S. assets from period to period, which is not a result of capital additions or disposals.

B. Liquidity and Capital Resources

Enterra's Liquidity

As an oil and gas producer Enterra has a declining asset base and therefore relies on ongoing development activities and acquisitions to replace production and add additional reserves. The Trust's future oil and natural gas production is highly dependent on Enterra's success in exploiting its asset base and acquiring or developing additional reserves.

Development activities and acquisitions may be funded internally through cash flow or through external sources such as debt or the issuance of equity. To the extent that cash flow is used to finance these activities, the cash available to distribute to unit holders is affected. Enterra's U.S. subsidiary is not restricted from transferring cash to the parent company. The Trust finances its operations and capital activities primarily with funds generated from operating activities, but also through the issuance of trust units, debentures and borrowing from its credit facility. The amount of equity Enterra raises through the issuance of trust units depends on many factors including projected cash needs, availability of funding through other sources, unit price and the state of the capital markets. The Trust believes its sources of cash, including bank debt, will be sufficient to fund its operations and anticipated capital expenditure program in 2009. Enterra's ability to fund its operations will also depend on operating performance and is subject to commodity prices and other economic conditions which may be beyond its control. The Trust will monitor commodity prices and adjust the 2009 capital expenditure program accordingly to stay within its means. Should external sources of capital become limited or unavailable, the Trust's ability to make the necessary development expenditures and acquisitions to maintain or expand Enterra's asset base may be impaired.

Enterra's improved cash position and available credit facility has put the Trust in reasonably good shape to deal with the current economic uncertainties and management is confident in its ability to manage through this cycle.

Enterra's capital structure at December 31, 2008 is follows:

	December 31, 2008		December 31, 2007	
Capitalization (in thousand of Canadian dollars except percentages)	Amount	%	Amount	%
Debt				
Bank indebtedness	95,466	47%	171,953	49%
Working capital (1)	(23,767)	(12%)	269	0%
Long-term receivable	(19,310)	(9%)	(4,003)	(1%)
Net debt	52,389	26%	168,219	48%
Convertible debentures	113,420	56%	111,692	32%
Trust units issued, at market	38,341	18%	68,517	20%
Total capitalization	204,150	100%	348,428	100%

(1) Working capital excludes commodity contracts and future income taxes.

Bank Indebtedness

At December 31, 2008, the Trust's bank indebtedness was $95.5 million a decrease of $76.5 million from the $172.0 million at December 31, 2007. The Trust has credit facilities with its banking syndicate that includes revolving and operating credit facilities which have a current borrowing capacity of $110.0 million

Enterra monitors capital using an interest coverage ratio that has been externally imposed as part of the credit agreement. Enterra is required to maintain an interest coverage ratio greater than 3.00 to 1.00; this ratio is calculated as follows:

	As at December 31	
(in thousands of Canadian dollars except for ratios)	2008	2007
Interest coverage (1):		
Cash flow over the prior four quarters	116,911	94,015
Interest expenses over the prior four quarters	18,088	21,732
Interest coverage ratio	6.46 : 1.00	4.33 : 1.00

(1) Note these amounts are defined terms within the credit agreements.

Working Capital

The working capital deficiency has decreased from the prior year due to Enterra's focus on debt reduction during 2008. In addition to the impact of high commodity prices, Enterra's reduction in expenditures during the fourth quarter of 2008 has decreased the working capital deficiency from December 31, 2007.

Enterra's working capital excluding bank indebtedness increased by $24.0 million due to an increase in cash of $10.1 million and an increase in accounts receivable of $15.7 million; these increases were slightly offset by an increase in accounts payable of $2.2 million. The increase in accounts receivables is due to an increase in the current receivable from a joint venture partner under the terms of a capital recovery agreement.

Enterra believes that its working capital is sufficient to fund its operations and the anticipated capital expenditure program in 2009.

	As at December 31	
Working Capital (in thousands of Canadian dollars)	2008	2007
Working capital (deficiency)(1)	(71,699)	(172,212)
Working capital (deficiency)(1) excluding bank indebtedness	23,767	(259)

(1) Working capital excludes commodity contracts and future income taxes.

Long-term Receivable

During 2006 Enterra entered into a farmout agreement with Petroflow Energy Ltd. ("JV Partner"), a public oil and gas company, to fund 100% of the drilling and completion costs of the undeveloped lands in Oklahoma. Under this farmout agreement, Enterra pays the cost to acquire the land and the JV Partner pays 100% of the drilling costs for producing wells. This resource play requires water to be pumped from the producing formation to allow the oil and gas to flow, so Enterra pays the initial costs of drilling saltwater disposal wells and related infrastructure but it recovers all of these costs from the JV Partner. This arrangement allows Enterra to add reserve barrels at finding and developing costs of less than $6.00 per boe which is very low in comparison to the industry averages. The long-term receivables are for these infrastructure costs incurred by Enterra that are to be repaid by the JV Partner over a three-year period and are subject to interest of 12.0% per annum. Based on current borrowing costs, Enterra is earning about a 7.5% interest premium in the interest that it is receiving from the JV Partner compared to Enterra's costs of borrowing. During 2008, $1.7 million of interest income was earned on the long-term receivables from JV Partner. In 2008, $5.0 million of principal payments have been received. The balance at year ended December 31, 2008 is $27.9 million (US$22.9 million) of which $8.6 million (US$7.0 million) is due within one year and has been included in accounts receivable.

Convertible Debentures

As at December 31, 2008, Enterra had $113.4 million of convertible debentures outstanding with a face value of $120.3 million. The debentures have the following conversion prices:

- ENT.DB – $9.25. Each $1,000 principal amount of ENT.DB debentures is convertible into approximately 108.108 Enterra trust units. Mature on December 31, 2011.
- ENT.DB.A - $6.80. Each $1,000 principal amount of ENT.DB.A debentures is convertible into approximately 147.059 Enterra trust units. Mature on June 30, 2012.

As at December 31, 2008, Enterra has issued capital of 62.2 million trust units outstanding. If all the outstanding convertible debentures were converted into units, a total of 76.8 million trust units would be outstanding.

Management believes that funds from operations are sufficient to meet its 2009 capital expenditure program and make interest payments on all debt. Although management's objective is to further reduce debt, the Trust does have unused credit facilities available should an appropriate opportunity present itself.

Financial Instruments

The Trust has a formal risk management policy which permits management to use specified price risk management strategies for up to 50% of its projected gross crude oil, natural gas and NGL production including fixed price contracts, costless collars and the purchase of floor price options and other derivative instruments to reduce the impact of price volatility and ensure minimum prices for a maximum of 24 months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this the Trust seeks to provide a measure of stability and predictability of cash inflows.

Enterra has recently been focusing its price risk management on purchasing floor price options to better maximize its exposure to upside price movements while trying to ensure sufficient cash flow to achieve its budgeted plans. As of December 31, 2008, less than one quarter of the oil and gas production of Enterra is economically hedged with commodity contracts that limit the maximum price for these commodities. For the winter heating season beginning November 1, 2008 and ending March 31, 2009, only commodity floor price contracts will remain on a portion of Enterra gas production.

At December 31, 2008, the following financial derivatives and fixed price contracts were outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Floor	Gas	8.00 ($/GJ)	3,000 GJ	November 1, 2008 – March 31, 2009
Floor	Gas	9.00 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	9.50 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	10.00 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Oil	72.00 (US$/bbl)	1,000 bbl	January 1, 2009 – December 31, 2009
Sold Call	Oil	91.50 (US$/bbl)	500 bbl	July 1, 2009 – December 31, 2009

Enterra had the following physical contracts outstanding as at December 31, 2008:

Fixed purchase	Power (Alberta)	62.90 (Cdn$/Mwh)	72 Mwh	July 1, 2007 – December 31, 2009

Since December 31, 2008, the following financial derivatives and fixed price contracts were entered into:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Fixed	Gas	5.01 (US$/mmbtu)	3,000 mmbtu	April 1, 2009 – October 31, 2009
Fixed	Gas	5.015 ($/GJ)	2,000 GJ	April 1, 2009 – October 31, 2009
Fixed Basis Differential (1)	Gas	Differential Fixed @ $1.08 US$/mmbtu	3,000 mmbtu	April 1, 2009 – October 31, 2009
Fixed Basis Differential (1)	Gas	Differential Fixed @ $1.10 US$/mmbtu	3,000 mmbtu	April 1, 2009 – December 31, 2009
Fixed	Gas	4.50 ($/GJ)	2,000 GJ	April 1, 2009 – December 31, 2009
Fixed	Gas	4.6725 (US$/mmbtu)	3,000 mmbtu	April 1, 2009 – December 31, 2009
Fixed	Gas	6.25 (US$/mmbtu)	5,000 mmbtu	November 1, 2009 – December 31, 2010
Fixed Basis Differential (1)	Gas	Differential Fixed @ $0.615 US$/mmbtu	5,000 mmbtu	November 1, 2009 – December 31, 2010
Fixed	Oil	50.00 (US$/bbl)	250 bbl	April 1, 2009 –June 30, 2009

Fixed	Oil	50.35 (US$/bbl)	200 bbl	July 1, 2009 – September 30, 2009
Fixed	Oil	65.00 ($/bbl)	300 bbl	July 1, 2009 – September 30, 2009
Fixed	Oil	85.00 ($/bbl)	500 bbl	October 1, 2009 – December 31, 2010

(1) NYMEX / Southern Star (Oklahoma) 2009 basis differential.

Material Commitments for Capital Expenditures

Currently, Enterra does not have any material commitment for capital expenditures. As an oil and gas producer, Enterra has a declining asset base and therefore relies on development activities and acquisitions to replace production and add additional reserves. The Trust's future oil and natural gas production is highly dependent on Enterra's success in exploiting its asset base and acquiring or developing additional reserves. Although the Trust has an internal inventory of drilling opportunities it continues to exploit, Enterra will evaluate alternatives external to this inventory but will also evaluate and act on accretive external acquisition opportunities. An expansion will be financed through cash flow, debt financing, farm in agreements or other corporate financings.

C. Research and Development, Patents and Licenses, etc.

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

D. Trend Information

Our financial results have been principally affected by fluctuating crude oil and natural gas prices and fluctuations in the Canadian to US dollar.

During 2008, the WTI oil price peaked above US$145.00 per barrel in July 2008 and has since fallen as much as US$110.00 per barrel by December 2008. Alberta natural gas settlement prices also increased in the first half of 2008 to $10.60/mcf before decreasing to $5.85/mcf by September 2008. During 2009, WTI crude oil prices have risen from the 2008 year end price of US$44.60 per barrel to over US$68.00 per barrel in June 2009.

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

E. Off Balance Sheet Arrangements

There were no off balance sheet arrangements in 2008 or 2007.

F. Tabular Disclosure of Contractual Obligations

Enterra has commitments for the following payments over the next five years:

Financial Instrument – Liability (in thousands of Canadian dollars)	1 Year	2 Years	3 Years	3-5 Years	5+ Years	Total
Bank indebtedness (1)	-	95,466	-	-	-	95,466
Interest on bank indebtedness (2)	3,580	1,790	-	-	-	5,370
Convertible debentures	-	-	80,331	40,000	-	120,331
Interest on convertible debentures	9,726	9,726	9,726	1,650	-	30,828
Accounts payable & accrued liabilities	37,949	-	-	-	-	37,949
Office leases (3)	1,506	1,597	2,130	925	-	6,158
Vehicle and other operating leases	373	117	-	-	-	490
Asset retirement obligations	3,014	4,090	1,193	3,983	9,871	22,151
Total obligations	56,148	112,786	93,380	46,558	9,871	318,743

(1) Assumes the credit facilities are not renewed on June 24, 2009.

(2) Assumes an interest rate of 3.75% (the rate on December 31, 2008).

(3) Future office lease commitments may be reduced by sublease recoveries totaling $1.6 million.

G. Safe Harbor

Please refer to the "Note Regarding Forward-Looking Statements" section at the introduction of this 20-F.

ITEM 6 - DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and Senior Management

Enterra's officers, directors and executive officers as of June 22, 2009 were:

Name and Municipality of Residence	Position with Enterra	Principal Occupation
Peter Carpenter Toronto, Ontario	Director (since 2006) and Chairman	Senior Partner & Director Claridge House Partners, Inc.
Roger Giovanetto Calgary, Alberta	Director (since 2006)	Business Consultant
Michael Doyle Calgary, Alberta	Director (since 2007)	Principal CanPetro International Ltd.
Victor Dusik Vancouver, British Columbia	Director (since 2008)	Chief Financial Officer Run of River Power Inc.
John Brussa Calgary, Alberta	Director (May 2009)	Partner , Burnet, Duckworth & Palmer LLP.
Don Klapko Calgary, Alberta	President and Chief Executive Officer Director (since 2008)	President and Chief Executive Officer Enterra Energy Corp.
Blaine Boerchers Calgary, Alberta	Senior Vice President, Finance and Chief Financial Officer (since 2007)	Sr. VP, Finance and Chief Financial Officer Enterra Energy Corp.
James (Jim) Tyndall Calgary, Alberta	Senior Vice President and Chief Operating Officer (since 2006)	Sr. VP and COO Enterra Energy Corp.
John F. Reader Calgary, Alberta	Senior Vice President Corporate Development (since 2005)	Sr. VP, Corporate Development Enterra Energy Corp.

Peter Carpenter, Director and Chairman

Peter Carpenter has been a Senior Partner (Oil and Gas) and Director of financial advisory firm Claridge House Partners, Inc. since 1996. His duties include sourcing equity financing and providing advisory services for the energy clients of the firm, including American Electric Power, the Hunt family, the Lundin Group and numerous junior oil companies. Mr. Carpenter is a Professional Engineer (Alberta) with a CFA designation and holds a B.Sc. in Chemical Engineering from the University of Alberta and an MBA from The University of Western Ontario. Mr. Carpenter joined EEC's Board of Directors in May 2006.

Roger Giovanetto, Director

Roger Giovanetto has been President of R&H Engineering, Ltd., a metallurgical, materials and corrosion engineering services company for more than five years. During his career, he has developed and managed oilfield chemical operations, corrosion consulting companies and started a publicly traded junior oil and gas company in Alberta. Mr. Giovanetto has also been instrumental in developing business operations in Siberia, where he specialized in renovating existing oilfields, and has established several chemical manufacturing facilities in Siberia and Iran. Mr. Giovanetto holds a B.Sc. in Metallurgical Engineering from the University of Alberta and is a member of APEGGA and other professional oil and gas organizations. Mr. Giovanetto joined EEC's Board of Directors in May 2006.

Michael Doyle, Director

Michael Doyle is a Professional Geophysicist with more than 35 years of wide–ranging experience in finding, developing and producing hydrocarbons. Mr. Doyle is a principal of privately held CanPetro International Ltd., and the Chairman of Madison Petrogas Ltd. He was previously a principal and President of Petrel Robertson Ltd. where he was responsible for providing advice and project management to clients in Canada and numerous other parts of the world. Prior to that, he held a variety of exploration positions at Dome Petroleum and Amoco Canada. He has served as a director of a number of companies principally in the petroleum sector, and has served on professional and technical committees, including an Alberta Hazardous Waste Committee. He also served as President of the Longview Rural Electrification Association through a period of growth that concluded with a sale to TransAlta Utilities. Mr. Doyle holds a Bachelor of Science (Math and Physics) from the University of Victoria where he has also served as a member of the Cooperative Education Advisory Council. Mr. Doyle joined EEC's Board of Directors in December 2007.

Victor Dusik, Director

Victor Dusik is a Chartered Accountant and Chartered Business Valuator with extensive experience including the areas of corporate finance, acquisitions and divestitures, risk management and public reporting and compliance. He is Chief Financial Officer of Run of River Power Inc., a publicly traded developer of environmentally friendly energy based in Vancouver, British Columbia. Previously, Mr. Dusik held the positions of Vice President Finance and Chief

Financial Officer with Maxim Power Corp., and Chief Executive Officer of Monarch Capital Limited. He spent more than 30 years in various progressive positions with Ernst & Young LLP providing public accounting and consulting services to a wide variety of companies and industry sectors. He served as a director of Taylor NGL Limited Partnership as well as several other public companies. Mr. Dusik holds a Master of Business Administration from the Richard Ivey School of Business, the University of Western Ontario. Mr. Dusik joined EEC's Board of Directors in February 2008.

John Brussa, Director

John Brussa is a Senior partner of Burnet, Duckworth & Palmer LLP, a Calgary-based law firm, specializing in the area of taxation. Mr. Brussa attended the University of Windsor where he received his law degree in 1981. He has been with Burnet Duckworth & Palmer LLP since 1982 and his current practice includes structured finance, taxation of international energy operations, corporate and income trust restructuring and reorganization, dispute resolution and acquisitions and divestitures. He has lectured extensively to the Canadian Tax Foundation, the Canadian Petroleum Tax Society and Insight. Mr. Brussa is also a director of a number of energy and energy-related corporations and income funds. In addition, Mr. Brussa is a past Governor of the Canadian Tax Foundation and is a director or trustee of a number of charitable or non-profit organizations.

Don Klapko, President and Chief Executive Officer

Don Klapko has over 30 years of oil and gas industry experience with the last nine years directly involved at the executive management level, most recently as President and Director of Trigger Resources Ltd., a private exploration and production company, and prior to that at Rio Alto Exploration Ltd. as Vice President of Operations. Earlier, Mr. Klapko worked in various technical and supervisory positions in oil and gas facilities, mechanical and operations functions. Mr. Klapko holds a Mechanical Engineering Technology Diploma from Kelsey Institute in Saskatchewan. He was appointed President and CEO in June 2008.

James H. (Jim) Tyndall, Senior VP Operations & COO

Jim Tyndall is a Professional Engineer with more than 26 years of diverse technical and managerial experience in the oil and gas industry, both domestically and internationally. Since 2002, Mr. Tyndall has held senior positions with three successful junior exploration companies involved in finding and developing properties in Western Canada. Earlier, he was with EnCana Corporation and its predecessor, PanCanadian Petroleum Ltd. for a total of 11 years, working in technical and management positions, including a four-year stint in Siberia. He was also with Hurricane Hydrocarbons in the Republic of Kazakhstan. Mr. Tyndall holds a Bachelor of Science degree in Engineering from the University of Saskatchewan. Mr. Tyndall joined EEC in June 2006.

John F. Reader, Senior VP Corporate Development

John Reader is a Professional Geological Engineer with over 25 years of resource industry experience. Recently he culminated an 18-year career with ChevronTexaco Corporation as Canadian Business Development Manager, with prior experience as Mergers and Acquisitions Manager, and various other supervisory roles. Mr. Reader was appointed Vice President, Operations and Engineering of EEC in October 2005 and was promoted to Senior Vice President Corporate Development in June 2006. Mr. Reader holds a Bachelor of Applied Science degree from the University of British Columbia and a Master of Business Administration from the University of Calgary.

Blaine Boerchers, Senior VP, Finance and Chief Financial Officer

Blaine Boerchers is a Chartered Accountant and a Certified Public Accountant (Texas) with over 20 years of experience in the energy industry, most recently as Vice President of Finance and Chief Financial Officer of Nabors Blue Sky Ltd. Mr. Boerchers has previously been Vice President of Finance and Chief Financial Officer of Airborne Energy Solutions Ltd. and has held various senior finance positions with Halliburton. During his 12 years of service with Halliburton, he also spent 4 years at Halliburton's corporate offices in Dallas, Texas with Halliburton's International Tax department in various roles. He spent 7 years in public practice in various roles, providing public accounting and consulting services to a variety of companies in various industries, primarily with Ernst & Young LLP. Mr. Boerchers holds a Bachelor of Commerce degree from the University of Calgary. He joined EEC in October 2007.

B. Compensation

The following table sets forth the annual compensation, including total compensation, for the financial year ended December 31, 2008 for the President and Chief Executive Officer, the Chief Financial Officer and the three other most highly compensated executive officers of the Trust and any of its subsidiaries (collectively called the "Named Executive Officers" or "NEOs").

Name & Principal Position	Year	Salary ($) (1)(2)	Share-based awards ($) (3)	Option-based awards ($) (4)	Non-equity incentive plan comp ($) Annual Incentive Plans (5)(6)(7)(8)	Long Term Incen-tive Plans	Pension value ($)	Other Comp ($) (9)(10)(11)	All other Comp ($) (12)(13)	Total Comp ($)
Trigger Projects Don Klapko	2008	240,000	-	-	600,000	-	-	-	-	840,000
Don Klapko, President & CEO	2008	253,846	2,303,280	-	-	-	-	4,000,000	28,096	6,585,222
Blaine Boerchers, CFO	2008	255,000	307,561	-	85,000	-	-	80,000	47,110	774,671
Jim Tyndall, Senior Vice President & COO	2008	286,000	469,167	-	85,000	-	-	80,000	30,840	951,007
John Reader, Senior Vice President Corporate Development	2008	265,000	435,680	-	85,000	-	-	80,000	-	865,680
John Chimahusky, Senior Vice President & COO U.S. Operations	2008	245,183	267,508	33,720	62,750	-	6,743	189,173	-	805,077

(1) Don Klapko's annual salary is $500,000. Payment is for partial year (June 27 to December 31, 2008).

(2) John Chimahusky's annual salary is US$230,000 and has been converted to C$ at the 2008 average annual exchange rate of 1.066

(3) RUs granted under the RUPU Plan. The value is calculated on the basis of the accounting fair value. The accounting fair value is calculated using the following formula: number of units grants less a forfeiture rate times the market value of the Trust Units, being their closing price on the TSX on the date prior to the date of grant. RUs are typically 3 year grants with 1/3 of the units issued after each year (see "Unit Option Plan and RUPU Plan" on page 16).

(4) John Chimahusky received a unit grant of 120,000 options on September 19, 2008 pursuant to the Unit Option Plan which are exercisable as follows: (i) for the first 1/3 of the options granted, immediate vesting; (ii) for the next 1/3 of the options granted, vesting on the first anniversary of John Chimahusky's hire date, December 3, 2007 and (iii) for the remaining 1/3 of the options granted, on the second anniversary of John Chimahusky's hire date. Any and all unexercised options shall expire on the fourth anniversary of John Chimahusky's hire date, December 3, 2011

(see "Unit Option Plan and RUPU Plan" on page 16).

In determining the fair value of John Chimahusky's option award, the Black-Scholes model, an established methodology, was used, with the following hypothesis:

(i) Risk-free interest rate: 2.50%;
(ii) Expected volatility in the market price of the shares: 90.0%;
(iii) Expected dividend yield: 0%; and
(iv) Expected life: 3.2 years.
Fair value per option: $0.2810

(5) Annual incentive for Trigger Projects consists of a bonus paid pursuant to the achievement of specific objectives (listed on 19) prior to contract completion.

(6) Don Klapko, President & CEO declined the annual incentive he was entitled to under the ABP (see "Bonus" on page 17).

(7) Annual incentives for Jim Tyndall, Blaine Boerchers, John Reader and John Chimahusky consist of the amounts earned under the ABP. These amounts were earned based on the bonus terms approved by the Enterra Board in January 2008 and were awarded based on the NEOs meeting their individual performance objectives through the year. The NEOs met their individual objectives (see "Annual Bonus Program" on page 15).

(8) John Chimahusky's ABP amount of US$50,000 has been converted to C$ at the exchange rate on the payment date, February 25, 2009 of 1.255.

(9) Don Klapko was rewarded with a signing bonus that will be paid out over a period of three years, the total amount to be $4,000,000. This is a one time reward in recognition of his achievements on behalf of the Trust prior to the date of his employment agreement and as an inducement to entering into his employment agreement (see "Other Income" on page 19).

(10) Other compensation paid to Jim Tyndall, Blaine Boerchers and John Reader was a retention bonus paid on May 31, 2008, which was put in place in November 2007, immediately after the former CEO resigned in order to ensure executive management continuity for the Trust.

(11) Other compensation paid to John Chimahusky on September 29, 2008 was a signing bonus in the amount of US$181,200, converted to C$ at the exchange rate on the payment date of 1.044.

(12) Perquisites for Don Klapko and Jim Tyndall include the Trust's contribution to their Unit Savings Plan as set out in "Trust Unit Savings Plan" on page 24, parking and other miscellaneous perquisites as required for business purposes,

(13) Perquisites for Blaine Boerchers include the Trust's contribution to his Unit Savings Plan as set out in "Trust Unit Savings Plan" on page 24, payment for 18 days of vacation he was unable to use in 2008, also parking and other miscellaneous perquisites as required for business purposes.

Outstanding Share-based and Option-based Incentive Plan Awards

The following table indicates for each of the Named Executive Officers all awards outstanding at the end of the 2008 financial year.

	Option-based awards				Share-based awards	
Name	Number of securities underlying unexercised options (#)	Option exercise price ($)	Option expiration date	Value of unexercised in-the-money options ($) (1)	Number of shares or units of shares that have not vested (#) (2)	Market or payout value of share-based awards that have not vested ($) (3)
Trigger Projects Don Klapko	-	-	-	-	-	-
Don Klapko, President & CEO	-	-	-	-	600,000	360,000
Blaine Boerchers CFO	150,000	1.65	Nov 26, 2011	-	138,333	83,000
Jim Tyndall,	100,000	15.49	Jun 5, 2011			
Senior Vice President & COO	150,000	1.65	Nov 26, 2011	-	161,651	96,991
	150,000	1.65	Nov 26, 2011			
John Reader,	75,000	17.05	May 1, 2011			
Senior Vice President, Corporate Development	30,000	23.26	Jan 25, 2010	-	146,927	88,156
John Chimahusky, Senior Vice President & COO, U.S. Operations	120,000	2.81	Dec 3, 2011	-	70,769	42,461

(1) None of the unexercised options (some of which have not yet vested) were in-the-money at the financial year end, December 31, 2008. The actual gains, if any, on exercise will depend on the value of the Trust Units on the date of option exercise (see "Unit Option Plan and RUPU Plan" on page 16).

(2) RUs granted under the RUPU Plan. The numbers include grants made in 2006, 2007 and 2008.

(3)

The market or payout value of the RU awards that have not vested is the number of RUs times the closing price of the Trust Units on December 31, 2008 on the TSX ($0.60).

Incentive-Plan Awards - Value Vested or Earned during the Year

The following table indicates for each of the Named Executive Officers the value on vesting of all awards and the bonus payout during the 2008 financial year.

Name	Option-based awards Value vested during the year ($) (1)	Share-based awards Value vested during the year ($) (2)	Non-equity incentive plan compensation Value earned during the year ($) (3)(4)(50(6)
Trigger Projects Don Klapko	-	-	600,000
Don Klapko, President & CEO	-	-	-
Blaine Boerchers CFO	-	25,643	85,000
Jim Tyndall, Senior Vice President & COO	-	164,459	85,000
John Reader, Senior Vice President, Corporate Development	-	139,296	85,000
John Chimahusky, Senior Vice President & COO, U.S. Operations	-	30,985	62,750

(1) The amount represents the aggregate dollar value that would have been realized if the options had been exercised on the vesting date, based on the difference between the closing price of the Trust Units on the TSX and the exercise price on such vesting date.
(2) The amount represents the aggregate dollar value that has been realized upon vesting of the RUs
(3) Trigger Projects payment consists of a bonus paid pursuant to the achievement of specific objectives prior to contract completion (see “Other Income” on page 19).
(4) Don Klapko, President & CEO declined the bonus he was entitled to under the ABP (see “Bonus” on page 17).
(5) Jim Tyndall, Blaine Boerchers, John Reader and John Chimahusky earned bonus payments under the ABP (see “Annual Bonus Program” on page 15). Bonus payments to Jim Tyndall, Blaine Boerchers and John Reader were made on February 17, 2009.
(6) John Chimahusky’s bonus payment of US$50,000 has been converted to C$ at the exchange rate on the payment date, February 25, 2009 of 1.255.

Pension Plan Benefits

In 2008 the Trust did not have a Defined Benefit or a Defined Contribution Pension Plan for the NEOs or for any of the Trust’s employees.

Trust Unit Savings Plan

For all of its Canadian employees, the Trust has an optional Trust Unit Savings Plan whereby the Canadian employees including the NEOs can contribute up to 9% of their base salaries through payroll deduction and the Trust will match their contribution. The combined contributions are used to purchase units of the Trust on a monthly basis. Employees can direct the contributions to a Registered Retirement Savings Plan (up to the annual maximum limit) or a non-registered savings account, or a combination of these two. Funds in the accounts can also be withdrawn or transferred to another financial institution. The Trust pays the administrative costs associated with the Trust Unit Savings Plan including up to two transfers or withdrawals per employee per year.

The following table indicates the value accumulated under the Trust Unit Savings Plan for each of the Canadian NEOs during the 2008 financial year:

Name	Accumulated Value at Start of Year ($) (1)	Compensatory ($) (2)	Non-compensatory ($) (3)	Accumulated Value at Year-end ($) (4)
Don Klapko, President & CEO	-	22,846	22,846	20,098
Blaine Boerchers CFO	-	22,856	22,856	11,753
Jim Tyndall, Senior Vice President & COO	19,595	25,740	25,740	14,057
John Reader, Senior Vice President, Corporate Development	12,990	-	-	6,186

(1) The accumulated value at the start of the year is based on the number of Trust Units held in the plan multiplied by the closing price of the Trust Units on the TSX on January 2, 2008 ($1.26)

(2) The compensatory amount is the Trust’s contribution to the plan.

(3) The non-compensatory amount is the NEOs contribution to the plan.

(4) The accumulated value at the end of the year is based on the number of Trust Units held in the plan multiplied by the closing price of the Trust Units on the TSX on December 31, 2008 ($0.60).

Simple Incentive Match Plan

For its U.S. employees, the Trust has a Simple Incentive Match Plan for Employees (“Simple Plan”). Employees can contribute up to a maximum of $10,500 per year plus an additional $2,500 for employees over the age of 50. The Trust matches the employee’s contribution up to 3% of their base salaries up to $4,900. The funds are held in individual self-directed employee accounts.

Effective January 1, 2009 the Trust is replacing the Simple Plan with a Safe Harbor 401(k) Plan. Employees will be able to contribute a maximum $16,500 plus an additional $5,500 for employees over the age of 50. The Trust will match the employee’s contribution up to 6% of their base salaries.

The following table indicates the value accumulated under the Simple Plan for the U.S. NEO during the 2008 financial year:

Name	Accumulated Value at Start of Year ($) (1)	Compensatory ($) (2)	Non-compensatory ($) (3)	Accumulated Value at Year-end ($) (4)
John Chimahusky, Senior Vice President & COO, U.S. Operations	-	6,743	12,703	14,497

(1) The accumulated value at the start of the year is based on the value of the funds invested in the plan on January 2, 2008.
(2) The compensatory amount is the Trust's contribution to the plan.
(3) The non-compensatory amount is the NEOs contribution to the plan.
(4) The accumulated value at the end of the year is based on the value of the funds invested in the plan on December 31, 2008.

REMUNERATION OF DIRECTORS

The Corporate Governance and Nomination Committee reviews the compensation of the Trust's non-employee Directors on an annual basis. The Committee reviews general compensation surveys to compare Enterra's director compensation policies to generally accepted practices for publicly traded companies.

During the last financial year, the annual compensation of non-employee directors was as follows, payable on a quarterly basis, in cash:

Annual Retainer - Chairman of the Board	$	45,000
Annual Retainer – All Other Directors	$	30,000
Board Meeting Fee – Chairman	$	2,500
Board Meeting Fee – Director	$	2,000
Special Committee Member fee (per month)	$	2,000
Special Committee Meeting Fee	$	1,000
All Other Committee Meetings as Chair	$	1,250
All Other Committee Meetings as Member	$	1,000

In November 2008, as a result of the significant responsibility undertaken by the Audit Committee Chairman, the Corporate Governance and Nominating Committee increased the annual retainer for the Audit Committee Chairman to $40,000 effective January 1, 2009.

In 2006 the Enterra Board approved RU grants for the then serving Directors. From 2006 to the date hereof the Enterra Board has continued to approve RU grants for the directors. The directors receive most of their compensation in the form of cash and the RU grants that have been granted to directors are small in relation to the RUs granted to employees of the Trust. However, the grants do provide directors with an ongoing equity stake in the Trust throughout their respective periods of Enterra Board service.

The directors who are also executives of the Trust receive no remuneration for serving as directors. Directors are reimbursed for transportation and other expenses for attendance at Board and Committee meetings.

The Trust does not have a retirement plan for directors. There are no other arrangements or service contracts under which directors were compensated in their capacity as directors by the Trust or its subsidiaries during the most recently completed financial year.

The following table provides details of the compensation received by the directors of Enterra during the 2008 financial year. Don Klapko, as an executive of the Trust receives no remuneration for serving as a Director.

Name	Fees earned ($)	Share-based awards ($) (2)	Option-based awards ($) (3)	Non-equity incentive plan compensation ($) (4)	Pension value ($) (5)	All other compen-sation ($) (6)	Total Compensation ($)
Peter Carpenter	104,000	41,496	-	-	-	-	145,496
Keith Conrad	-	-	-	-	-	-	-
Michael Doyle	81,795	41,496	-	-	-	-	123,291
Victor Dusik	74,942	41,496	-	-	-	-	116,438
Roger Giovanetto	65,750	41,496	-	-	-	-	107,246
Don Klapko (1)	-	-	-	-	-	-	-

(1) RUs granted under the RUPU Plan. The value is calculated on the basis of the accounting fair value. The accounting fair value is calculated using the following formula: number of units grants less a forfeiture rate times the market value of the Trust Units, being their closing price on the TSX on the date prior to the date of grant. RUs are typically 3 year grants with 1/3 of the units issued after each year (see "Unit Option Plan and RUPU Plan" on page 16).

(2) None of the directors received options under the Unit Option plan.

(3) None of the directors received any form of non-equity incentive plan compensation.

(4) The Trust does not have a retirement plan for Directors.

(5) The directors, other than Don Klapko who is an executive of the Trust, are reimbursed for transportation and other expenses for attendance at Enterra Board and Committee meetings. There are no other arrangements under which the Directors were compensated by the Trust or its subsidiaries during the most recently completed financial year.

(6) Mr. Conrad resigned from the Enterra Board effective February 20, 2008.

C. Board Practices

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

Committees of the Board of Directors

Committees

The board of EEC has constituted five committees for the purpose of discharging specific mandates in relation to the stewardship of EEC, including the administration and management of the Trust, being the Corporate Governance and Nominating Committee, the Audit Committee, the Compensation Committee, the Reserves Committee and the Health Safety Regulatory Compliance and Environmental Committee. In addition, an independent committee (the "Special Committee") has been constituted for the purpose of addressing issues related to Macon Resources Ltd. and Petroflow as detailed under "Special Committee" below.

Corporate Governance and Nominating Committee

EEC has established a Corporate Governance and Nominating Committee comprised of 3 non-management members of the board of EEC. The Corporate Governance committee consists of Michael Doyle, Victor Dusik and Roger Giovanetto. The mandate of the Corporate Governance and Nominating Committee is to recommend to the full board of EEC policies and specific matters respecting (i) policies and procedures of corporate governance; (ii) identifying nominees for the board of EEC, and (iii) conducting an annual performance review of the directors.

Audit

EEC has established an Audit Committee (the "Audit Committee") comprised of three members: Victor Dusik, Roger Giovanetto and Michael Doyle, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral Instrument 52-110 – Audit Committees. The mandate of the Audit Committee is to assist the board of EEC in its oversight of the integrity of our financial and related information, including the financial statements, internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements. In doing so, the Audit Committee oversees the audit efforts of our external auditors and, in that regard, is empowered to take such actions as it may deem necessary to satisfy itself that our external auditors are independent of us.

Compensation

EEC has established a Compensation Committee comprised of 3 non-management members of the board of ECC. The compensation Committee at December 31, 2008 consists of Michael Doyle, Victor Dusik and Roger Giovanetto. The mandate of the Compensation Committee is to review and recommend to the board of directors of EEC:

- executive compensation policies, practices and overall compensation philosophy;

- total compensation packages for all employees who receive aggregate annual compensation in excess of $100,000;

- bonus and trust unit options;

- major changes in benefit plans; and

- the adequacy and form of directors' compensation to ensure it realistically reflects the responsibilities and risks of membership on the board of EEC.

Reserves

EEC has established a Reserves Committee comprised of 3 non-management members of the board. The reserves committee is Peter Carpenter, Victor Dusik and Roger Giovanetto. The mandate of the Reserves Committee is to:

- review the selection of an independent engineer for undertaking each reserves evaluation as the same may be required from time to time;

- consider and review the impact of changing independent engineering firms;

- receive the engineering report and consider the principal assumptions upon which it is based; and

- consider and review management's input into independent engineering reports and the key assumptions used.

Health Safety Regulatory Compliance and Environmental Committee

The Health Safety Regulatory Compliance and Environmental Committee currently consists of Mr. Carpenter (Chairman), Mr. Doyle and Mr. Dusik. The mandate of this Committee is to review the nature and extent of compliance in the areas of health, safety, regulatory compliance and Environmental matters.

Special Committee

EEC established an Independent Committee composed of 3 non-management members of the board of directors. The special committee was Peter Carpenter, Michael Doyle and Victor Dusik.

The mandate of the Special Committee was to:

- the Chairman of the Special Committee, acting as the Chief Executive Officer
- search for and negotiate terms of employment for a President and CEO candidate;
- formulate a CEO succession plan;
- review alternatives to strengthen the balance sheet;
- formulate a go forward strategy with the assistance of our financial advisors;

- review and resolve any conflicts of interest that exist; and
- report its findings to the board of directors of EEC and make such recommendations as the Special Committee considers appropriate.

The Special Committee was disbanded after Mr. Klapko was hired as President and Chief Executive Officer.

D. Employees

At December 31, 2008, the Trust employed or contracted 54 office personnel and 36 field operations personnel in its Canadian operations and 20 office personnel and 33 field operations personnel in its U.S. operations for a total of 143 employees.

E. Share Ownership

The percentage of Trust Units that were owned, directly or indirectly, by all directors and officers of Enterra as of June 18, 2009 as a group was 0.48% (approximately 296,717 Trust Units).

The following table sets forth the number of units, options and unvested units held by the members of the Board of Directors as at June 18, 2009.

Name	Number of units held (#)	Number of securities underlying unexercised options (#)	Option exercise price ($)	Option expiration date	Number of units that have not vested (#)
Peter Carpenter, Director	4,250	10,000	15.55	May 18, 2011	10,000
Roger Giovanetto, Director	4,697	10,000	15.55	May 18, 2011	10,000
Michael Doyle, Director	7,050	-	-	-	10,000
Victor Dusik, Director	2,815	-	-	-	10,000
John Brussa, Director	-	-	-	-	-

The following table sets forth the number of units, options and unvested units held by the officers of the Trust at June 18, 2009.

Name	Number of units held	Number of securities underlying unexercised options	Option exercise price	Option expiration date	Number of units that have not

	(#)	(#)	($)		vested (#)
Don Klapko, President & CEO	52,026	-	-	-	600,000
Blaine Boerchers CFO	49,190	150,000	1.65	Nov 26, 2011	138,333
Jim Tyndall, Senior Vice President & COO	115,430	100,000	15.49	Jun 5, 2011	145,831
		150,000	1.65	Nov 26, 2011	
John Reader, Senior Vice President, Corporate Development	61,259	150,000	1.65	Nov 26, 2011	135,422
		75,000	17.05	May 1, 2011	
		30,000	23.26	Jan 25, 2010	

ITEM 7 - MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. Major Shareholders

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

B. Related Party Transactions

On November 23, 2007, Enterra entered into a consulting agreement with Trigger Projects Ltd. for management services that would effectively be expected of the most senior manager of the Trust. This relationship was entered into to provide temporary executive management services after the former Chief Executive Officer resigned. This contract had terms that required payment for services of $40,000 per month and a bonus of up to $0.5 million on termination. The contract expired on May 31, 2008 and was extended to June 26, 2008. During 2008, total payments of $0.8 million were made to Trigger Projects Ltd. and no balance was outstanding at December 31, 2008.

In 2006 Enterra entered into a farm-out agreement with Petroflow Energy Ltd. ("JV Partner"), a public oil and gas company, to fund the drilling and completion costs of the undeveloped lands in Oklahoma. Per the agreement, JV Partner pays 100% of the drilling and completion costs to earn 70% of Enterra's interest in the well and Enterra is required to pay 100% of the infrastructure costs to support these wells, such as pipelines and salt water disposal wells. The infrastructure costs paid by Enterra are recoverable from JV Partner over three years with interest charged at a rate of 12% per annum. Infrastructure costs paid by Enterra are accounted for as a capital lease, therefore, the capital costs incurred are not included in property, plant and equipment but are current and long-term receivables. The interest income on the long-term receivables is recorded as a reduction in interest expense. The former Chief Executive Officer and former director of Enterra owned, directly and indirectly, approximately 16% of the outstanding shares of JV Partner during his tenure at Enterra. A current director of Enterra owns approximately 2% of the outstanding shares of JV Partner. As at December 31, 2008, a total of $27.9 million, split between $8.6 million of trade receivables and $19.3 million of long-term receivables, relate to infrastructure costs incurred by Enterra on behalf of JV Partner that are due from JV Partner. The receivables are for infrastructure costs incurred that are to be repaid by JV Partner over a three-year period and is subject to interest of 12% per annum. For the year ended December 31, 2008, $1.7 million of interest income was earned on the long-term receivables from JV Partner (2007 – $0.4 million). In 2008, $5.0 million of principal payments have been received (2007 - $1.1 million).

In 2007, Enterra paid Macon Resources Ltd. ("Macon") $0.7 million, a company 100% owned by the former Chief Executive Officer, for management services provided by the former Chief Executive Officer. Macon did not provide any services to Enterra during 2008 and therefore there were no payments made in 2008. During Q1 2007, 50,000 restricted units (valued at $0.4 million based on the unit price of trust units on the grant date) were granted to Macon. On February 28, 2007, these restricted units vested and were converted to 50,441 trust units. The former Chief Executive Officer resigned as an officer and director on November 27, 2007 and February 20, 2008 respectively.

Relationship with JED Oil Inc. and JMG Exploration Inc.

On January 1, 2006, Enterra terminated a Technical Services Agreement with JED Oil Inc ("JED"), which had provided for services required to manage the Trust's field operations and governed the allocation of general and administrative expenses between the two entities. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On September 28, 2006, Enterra terminated the existing farmout, joint services and an Agreement of Business Principles with JED. Concurrent with the termination of the agreements, the Trust settled all amounts owing to JED.

In September 2006, Enterra sold $44.0 million of petroleum and natural gas properties to JED in exchange for $30.9 million of petroleum and natural gas properties and the settlement of the $13.1 million balance due to JED.

Previously, under an Agreement of Business Principles, properties acquired by the Trust were contract operated and drilled by JMG Exploration, Inc. ("JMG"), a publicly traded oil and gas exploration company, if they were exploration properties, and contract operated and drilled by JED, a publicly traded oil and gas development company, if they were development projects. Exploration of the properties was done by JMG, which paid 100% of the exploration costs to earn a 70% working interest in the properties. If JMG discovered commercially viable reserves on the exploration properties, the Trust had the right to purchase 80% of JMG's working interest in the properties at a fair value as determined by independent engineers. Had the Trust elected to have JED develop the properties, development would have been done by JED, which would pay 100% of the development costs to earn 70% of the interests of both JMG and the Trust. The Trust had a first right to purchase assets developed by JED.

C. Interests of Experts and Counsel
Not applicable.

ITEM 8 - FINANCIAL INFORMATION

A. Consolidated Statements and Other Financial Information
See Item 18 – Financial Statements.

B. Significant Changes
There were no significant changes since December 31, 2008, the date of the financial statements.

ITEM 9 - THE OFFER AND LISTING

A. Offer and Listing Details

1. Expected Price of Shares Offered
Not Applicable.

2. Market for Securities Offered
Not Applicable.

3. Purchase Rights
Not Applicable.

4. Price Range of Common Stock and Trading Markets

Our Trust Units are listed on the Toronto Stock Exchange (ENT.UN) and the New York Stock Exchange (ENT). The following table sets forth the price range and trading volume of our Trust Units as reported by the TSX and the NYSE for the periods indicated:

	TSX		NYSE	
	High ($)	Low ($)	High (US$)	Low (US$)

Year ended 2008	5.15	0.58	5.08	0.47
Year ended 2007	9.68	1.00	8.25	1.04
Year ended 2006	22.46	7.75	19.50	6.78
Year ended 2005	32.32	18.50	26.75	15.76
Year ended 2004	24.00	13.01	19.47	10.10
Quarter ended December 31, 2008	2.45	0.58	2.29	0.47
Quarter ended September 30, 2008	4.80	2.07	4.80	1.93
Quarter ended June 30, 2008	5.15	1.76	5.08	1.74
Quarter ended March 31, 2008	2.62	1.14	2.66	1.16
Quarter ended December 31, 2007	2.96	1.00	2.99	1.04
Quarter ended September 30, 2007	6.50	1.35	6.18	1.33
Quarter ended June 30, 2007	6.95	5.69	6.41	4.96
Quarter ended March 31, 2007	9.68	5.76	8.25	4.88
Six most recent months ended:				
May 31, 2009	1.70	1.20	1.53	1.04
April 30, 2009	1.62	0.74	1.35	0.59
March 31, 2009	0.92	0.55	0.79	0.41
February 28, 2009	0.80	0.53	0.65	0.43
January 31, 2009	0.91	0.57	0.77	0.47
December 31, 2008	1.09	0.58	0.92	0.47

Our Debentures are listed on the Toronto Stock Exchange (ENT.DB, ENT.DB.A). The following table sets forth the price range and trading volume of our Debentures as reported by the TSX for the periods indicated:

	TSX (ENT.DB)		TSX (ENT.DB.A)	
	High ($)	Low ($)	High ($)	Low ($)
Year ended 2008	97.50	55.00	100.50	62.00
Year ended 2007	104.25	60.00	104.50	60.00
Year ended 2006	121.00	100.00	N/A	N/A
Year ended 2005	N/A	N/A	N/A	N/A
Year ended 2004	N/A	N/A	N/A	N/A
Quarter ended December 31, 2008	91.00	55.00	93.50	62.00
Quarter ended September 30, 2008	97.50	92.00	100.50	92.00
Quarter ended June 30, 2008	96.00	85.00	100.50	86.00
Quarter ended March 31, 2008	94.70	68.01	90.00	75.05
Quarter ended December 31, 2007	97.00	60.00	93.00	60.00
Quarter ended September 30, 2007	100.00	75.00	102.00	77.00
Quarter ended June 30, 2007	100.00	94.67	104.50	99.75
Quarter ended March 31, 2007	104.25	93.00	N/A	N/A
Six most recent months ended:				
May 31, 2009	75.00	65.00	78.00	66.50
April 30, 2009	69.00	62.90	69.00	59.00
March 31, 2009	68.25	50.00	62.50	59.00

February 28, 2009	65.01	55.00	65.00	58.00
January 31, 2009	66.00	55.00	70.00	55.00
December 31, 2008	72.00	55.00	68.50	62.00

B. Plan of Distribution
Not applicable

C. Markets
Our Trust units are listed on the Toronto Stock Exchange (ENT.UN) and the New York Stock Exchange (ENT).

D. Selling Shareholders
Not applicable

E. Dilution
Not applicable

F. Expenses of the Issue
Not applicable.

ITEM 10 – ADDITIONAL INFORMATION

A. Share Capital
Not applicable.

B. Trust Indenture / Memorandum and Articles of Incorporation
The Trust

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

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

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

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

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

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

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

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

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

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

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

C. Material Contracts

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

- Second Amended and Restated Credit Agreement dated June 25, 2008 among Enterra Energy Corp. and the Bank of Nova Scotia and a syndicate of lenders including Bank of Nova Scotia.

D. Exchange Controls

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

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

E. Taxation

Canadian Federal Income Tax Considerations

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

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

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

Agency (the “CRA”).

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

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

Residents of Canada

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

Status of the Trust

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

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

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

2. the Trust must comply on a continuous basis with certain requirements relating to the qualification of the trust units for distribution to the public, the number of Unitholders and the dispersal of ownership of trust units. In this regard, there must be at least 150 Unitholders, each of whom owns not less than one "block" of trust units having a fair market value of not less than $500. A "block" of trust units means 100 trust units if the fair market value of one trust unit is less than $25; and
3. continuously from the time of its creation, all or substantially all of the Trust's property must consist of property other than property that would be "taxable Canadian property" for purposes of the Tax Act.

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

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

Taxation of the Trust

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

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

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

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

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

For purposes of the Tax Act, the Trust generally intends to deduct, in computing its income and taxable income, the full amount available for deduction in each year. As a result of such deductions and the Trust’s entitlement to a Capital Gains Refund, it is expected that the Trust will not be liable for any material amount of tax under the Tax Act. However, no assurance can be given in this regard.

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

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

On October 31, 2006 the Canadian Minister of Finance announced certain changes to the taxation of publicly traded trusts (“Bill C-52”). Bill C-52, the Budget Implementation Act 2007 received its third reading and was substantively enacted on June 12, 2007. Bill C-52 applies to a specified investment flow-through (“SIFT”) trust and will apply a tax at the trust level on distributions of certain income from such SIFT trusts at a rate of tax comparable to the combined federal and provincial corporate tax rate. These distributions will be treated as dividends to the trust unitholders. The Trust constitutes a SIFT and as a result, the Trust and its unitholders will be subject to Bill C-52.

Bill C-52 commenced January 1, 2007 for all SIFT’s that began to be publicly traded after October 31, 2006 and commencing January 1, 2011 for all SIFT’s that were publicly traded on or before October 31, 2006. It is expected that the Trust will not be subject to the taxation requirements of Bill C-52 until January 1, 2011.

Commencing January 1, 2011, the Trust will not be able to deduct certain of its distributed income. The Trust will become subject to a distribution tax ranging from 25 to 28 percent, depending on the amount of taxable income allocated to various provinces on distributions of income, but this tax will not apply to returns of capital. Enterra will consider the options and alternative structures with legal and business advisors to determine if any potential restructuring available to maximize value is in the best interest of unitholders.

The federal component of the proposed tax on SIFT is expected to be 15 percent in 2012 (25 to 28 percent in total including provincial income taxes) and thereafter. The Trust is required to recognize, on a prospective basis, future income taxes on temporary differences in the Trust.

Taxation of Unitholders

Income from trust units

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

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

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

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

Cost of trust units

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

Disposition of trust units

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

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

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

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

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

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

Tax-Exempt Unitholders

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

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

Taxation of Capital Gains and Capital Losses

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

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

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

Non-Residents of Canada

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

Taxation of the Trust

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

Taxation of Income from Trust Units

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

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

Disposition of trust units

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

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

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

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

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

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

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

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

United States Federal Income Tax Considerations

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

This summary does not purport to be a complete description of all of the United States federal income tax considerations that may be relevant to a U.S. Holder. In particular, this summary deals only with U.S. Holders who hold Enterra common shares as a capital asset. This summary does not address the tax treatment of U.S. Holders who are subject to special tax rules. Nor does this summary discuss the United States federal income tax considerations for a partner in a partnership which holds Enterra common shares or trust units.

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

Enterra should be treated as a partnership for U.S. federal income tax purposes. As such, a U.S. holder will include in each of its taxable years its share of our items of income, gain, loss, deduction and credit whether or not we make any distribution. Such items of income, gain, loss, deduction and credit will be determined under United States federal income tax principles and will as a general matter retain their character and source as they flow through us to the holders of trust units. The use by a holder of trust units of certain of our items of deduction, loss and credit will be limited as is discussed below.

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

Tax Rates and Creditability of Certain Canadian Income Taxes.

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

United States Federal Income Tax Rates

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

For a U.S. holder who is an individual, any long-term capital gain that is realized on the sale or other disposition of trust units (including any part of a distribution that is treated as gain on such shares that is a long-term capital gain) would be subject to tax at a maximum rate of 15 percent until the end of 2010 under current law. Each U.S. holder should discuss with its own advisor whether a person whose holding period in us is less than one year can claim such 15 percent tax rate.

Credits for Canadian Income Taxes

As a general matter, any Canadian income taxes that are withheld from distributions are foreign income taxes that, subject to generally applicable limitations under United States law, may be used by a U.S. holder as a credit against its United States federal income tax liability or as a deduction (but only for a taxable year for which such U.S. holder elects to do so with respect to all foreign income taxes). So long as we are a partnership for United States federal income tax purposes, the provisions of Section 901(k) of the Internal Revenue Code should not apply. If we were a corporation for such purposes, then a U.S. Holder would not be able to claim the foreign tax credit with respect to any such Canadian tax that is withheld on a distribution that we made unless such U.S. holder had held the trust units for a minimum period (subject to certain tolling rules) of at least 16 days during the 30 day period beginning on the date which is 15 days before the date on which the trust units went ex-dividend with respect to such dividend or to the extent such U.S. holder is under an obligation to make related payments with respect to substantially similar or related property. It is likely that the Internal Revenue Service will take the position that the holding period requirement that is summarized in the preceding sentence is measured as to an individual partner of us in respect of any Canadian taxes paid by us in respect of dividends that we receive by the holding period in the trust units.

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

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

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

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

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

Tax-Exempt Organizations and Other Investors

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

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

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

Administrative Matters

Nominee Reporting

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

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is:

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

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

(iii) a tax-exempt entity;

- the amount and description of trust units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

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

Registration as a Tax Shelter

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

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

Reportable Transactions

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

Other Tax Considerations

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

F. Dividends and Paying Agents

Not applicable

G. Statement by Experts

Not applicable

H. Documents on Display

It is possible to read and copy documents referred to in this annual report on Form 20-F that have been filed with the SEC at the SEC's public reference room located at 100 F Street, NE, Room 1580, Washington, DC 20549 and at the SEC's other public reference rooms in New York City and Chicago. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms and their copy charges. The SEC filings are also available to the public from commercial document retrieval services and in the website maintained by the SEC at www.sec.gov. It is also possible to read and copy documents referred to in this annual report on Form 20-F at the New York Stock Exchange, 20 Broad Street, 17th floor, New York.

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

Enterra Energy Trust
Suite 2700, 500 – 4th Avenue S.W.
Calgary, Alberta, Canada
T2P 2V6
(403) 263-0262

I. Subsidiary Information

Not applicable

ITEM 11- QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the current volatile economic and financial market conditions, the Trust continually assesses its risks and manages those risks to the best of its abilities. The Trust is exposed to normal market risks inherent in the oil and natural gas business, including commodity price risk, credit risk, financing risk, foreign currency and environmental risk. From time to time, Enterra attempts to mitigate its exposure to these risks by using commodity contracts and by other means. These risks are described in more detail in Note 13 to the consolidated financial statement.

Commodity Price Risk

Commodity price fluctuations are among the Trust's most significant exposures. Crude oil prices are influenced by worldwide factors such as supply and demand fundamentals, OPEC actions and political events. Natural gas prices are influenced by oil prices, North American natural gas supply and demand factors including weather, storage levels and LNG imports. In accordance with policies approved by the Board of Directors, the Trust may, from time to time, manage these risks through the use of fixed physical contracts, swaps, collars or other commodity contracts

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. The receivables are principally with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Trust continues to assess the strength of its counterparties and tries to do business with high quality companies with substantial assets. The counter parties on the commodity contracts are generally large well financed companies and all new contracts are being executed with only the strongest of these companies to manage the exposure from counterparty risk. Management continuously monitors credit risk and credit policies to ensure exposures to customers are limited. The Trust believes that the financial strength of its Bank syndicate, which consists of the Bank of Nova Scotia, HSBC Bank Canada and Union Bank of California, appears to be relatively strong and has confirmed their commitment to Enterra and has provided assurance that they are not unduly impacted by the recent turmoil in credit markets.

Financing Risk

Enterra currently maintains a portion of its debt in floating-rate bank facilities which results in exposure to fluctuations in short-term interest rates which have, for a number of years, been lower than longer-term rates. In June 2009, Enterra completed a borrowing base review with its lenders where its revolving and operating credit facilities borrowing capacity of $110.0 million was established. Enterra's syndicate of lenders, consisting of Bank of Nova Scotia, HSBC Bank Canada and Union Bank of California have confirmed their commitment to Enterra and have indicated that they are not unduly impacted by the recent turmoil in credit markets.

Foreign Currency Rate Risk

Enterra's U.S. operations accounted for 45% of Enterra's total 2008 production; therefore, fluctuations in the U.S. dollar to Canadian dollar exchange rate will impact the Trust's revenues due to the Trust translating the revenues from the U.S. operations into Canadian dollars. The Trust also has commodity contracts denominated and settled in U.S. dollars.

Environmental Risk

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of Enterra or its working interests. Such legislation may be changed to impose higher standards and potentially more costly obligations on Enterra. There is uncertainty regarding the Federal Government's Regulatory Framework for Air Emissions ("Framework"), as issued under the Canadian Environmental Protection Act. Additionally, the potential impact on the Trust's operations and business of the Framework, with respect to instituting reductions of greenhouse gases, is not possible to quantify at this time as specific measures for meeting Canada's commitments have not been developed.

Liquidity Risk

Liquidity risk is the risk that Enterra is unable to meet its financial liabilities as they come due. Management utilizes a long-term financial and capital forecasting program that includes continuous review of debt forecasts to ensure credit facilities are sufficient relative to forecast debt levels, distribution and capital program levels are appropriate, and that financial covenants will be met. In the short term, liquidity is managed through daily cash management activities, short-term financing strategies and the use of collars and other commodity contracts to increase the predictability of minimum levels of cash flow from operating activities. Additional information on specific instruments is discussed in Item 5 and in Note 13 to the consolidated financial statements.

Enterra has commitments for the following payments over the next five years:

Financial Instrument – Liability (in thousands of Canadian dollars)	1 Year	2 Years	3 Years	3-5 Years	5+ Years	Total
Bank indebtedness (1)	-	95,466	-	-	-	95,466
Interest on bank indebtedness (2)	3,580	1,790	-	-	-	5,370
Convertible debentures	-	-	80,331	40,000	-	120,331
Interest on convertible debentures	9,726	9,726	9,726	1,650	-	30,828
Accounts payable & accrued liabilities	37,949	-	-	-	-	37,949
Office leases (3)	1,506	1,597	2,130	925	-	6,158
Vehicle and other operating leases	373	117	-	-	-	490
Asset retirement obligations	3,014	4,090	1,193	3,983	9,871	22,151
Total obligations	56,148	112,786	93,380	46,558	9,871	318,743

(1) Assumes the credit facilities are not renewed on June 24, 2009.
(2) Assumes an interest rate of 3.75% (the rate on December 31, 2008).
(3) Future office lease commitments may be reduced by sublease recoveries totaling $1.6 million.

ITEM 12- DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not Applicable.

PART II

ITEM 13- DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None

ITEM 14- MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable

ITEM 15- CONTROLS AND PROCEDURES

(a) Disclosure controls and procedures.

As of December 31, 2008, an internal evaluation was carried out of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the

Trust files or submits under the Exchange Act or under Canadian Securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act or under Canadian Securities Legislation is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. The Trust has undertaken a review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2008, based on that evaluation, the Trust's internal controls were found to be operating effectively and no material weaknesses existed. The effectiveness of Enterra's internal control over financial reporting as at December 31, 2008 was audited by KPMG LLP, an independent registered public accounting firm.

For the December 31, 2007 reporting period it was identified that as a result of turnover within Senior Management during 2007, the potential for control weaknesses was heightened. Enterra took action to fill these Senior Management positions in Q4 2007 with individuals that have the necessary experience and knowledge to address the complexity of the financial reporting requirements and there have been no changes in these positions during 2008. Throughout the year the new Senior Management team was in place and changes to internal control processes were made to resolve the material weakness that existed at December 31, 2007. The Trust completed testing of its internal controls over financial reporting in Q4 2008 and was able to conclude that no material control weakness existed at December 31, 2008.

(c) Attestation report of the registered public accounting firm

The attestation report of the independent registered chartered accountants on the effectiveness of internal control over financial reporting is included under the heading "Report of Independent Registered Chartered Accountants" in Item 18 to this Annual Report on Form 20-F.

(d) Changes in internal controls.

For the December 31, 2007 reporting period it was identified that as a result of turnover within Senior Management during 2007, the potential for control weaknesses was heightened. Enterra took action to fill these Senior Management positions in Q4 2007 with individuals that have the necessary experience and knowledge to address the complexity of the financial reporting requirements and there have been no changes in these positions during 2008. Throughout the year the new Senior Management team was in place and changes to internal control processes were made to resolve the material weakness that existed at December 31, 2007. The Trust completed testing of its internal controls over financial reporting in Q4 2008 and was able to conclude that no material control weakness existed at December 31, 2008.

ITEM 16. [RESERVED]

ITEM 16A. AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of Enterra Energy Corp., on behalf of the Registrant, has determined that Mr. Victor Dusik, a member and the chairman of the Registrant's Audit Committee, is an "audit committee financial expert" (as such term is defined by the rules and regulations of the Securities and Exchange Commission) and is "independent" (as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

ITEM 16B. CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined by the rules and regulations of the Securities and Exchange Commission), entitled the "Code of Business Conduct" that applies to each director, officer (including its principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions), employee and consultant of the Registrant. The Code of Business Conduct is available for viewing on the Registrant's website at www.enterraenergy.com under "Corporate Governance" and is attached in the exhibits to this document. There were not any amendments to any provision of the Code of Business Conduct during the fiscal year ended December 31, 2008. Further, during the fiscal year ended December 31, 2008, there were not any waivers, including implicit waivers, granted from any provision of the Code of Business Conduct that applied to the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions.

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees

KPMG LLP audited the annual financial statements for the 2008 and 2007 fiscal year.

(in $ thousands)	2008	2007
Audit fees (1)	530.1	701.0
Audit-related fees (2)	75.0	82.0
Tax fees (3)	-	-
All other fees (4)	10.2	84.0
Total	615.3	867.0

Notes:

(1) Audit fees include professional services rendered by KPMG LLP for the audit of the annual consolidated financial statements as well as services provided in connection with statutory and regulatory filings and engagements.

(2) Audit-related fees are fees charged by KPMG LLP for reviews of the Trust’s interim financial statements.

(3) Tax fees include fee for tax compliance, tax advice and tax planning.

(4) All other fees related to advisory for International Financial Reporting Standards, SOX-404 compliance and document translation.

The Registrant's Audit Committee has implemented a policy restricting the services that may be provided by the Registrant's auditors. Prior to the engagement of the Registrant's auditors to perform both audit and non-audit services, the Audit Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Audit Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding an adverse impact on auditor independence. All audit and non-audit fees paid to KPMG LLP in 2007 and 2008 were pre-approved by the Registrant's Audit Committee and none were approved on the basis of the de minimis exemption set forth in Rule 2-01(c)(7)(i)(C) of Regulation S-X. Based on the Audit Committee's discussions with management and the independent auditors, the committee is of the view that the provision of the non-audit services by KPMG LLP described above is compatible with maintaining that firm's independence from the Registrant.

ITEM16D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM16E. PURCHASE OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Not applicable.

ITEM16F. CHANGE IN REGISTRANTS CERTIFIED ACCOUNTANT

Not applicable.

ITEM16G. CORPORATE GOVERNANCE

The Registrant has reviewed the New York Stock Exchange's corporate governance rules and confirms that the Registrant's corporate governance practices are not significantly nor materially different than those required of domestic companies under the New York Stock Exchange's listing standards except that, as a foreign private issuer, the Registrant is not obligated to and does not have an internal audit function.

PART III

ITEM 17 – FINANCIAL STATEMENTS

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

ITEM 18 – FINANCIAL STATEMENTS

Index to Financial Statements;

Reports KPMG LLP, Independent Auditors
Consolidated Balance Sheets at December 31, 2008 and 2007
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
Consolidated Statements of Deficit
Consolidated Statements of Cash Flows
Notes to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterra Energy Corp., as Administrator of Enterra Energy Trust

We have audited the consolidated balance sheets of Enterra Energy Trust (the "Trust") as at December 31, 2008 and 2007 and the consolidated statements of income (loss) and comprehensive income (loss), deficit and cash flows for each of the years in the three-year period ended December 31, 2008. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the years ended December 31, 2008 and 2007, we also conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2008 in conformity with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principles vary in certain significant respects from US generally accepted accounting principles. Information relating to the nature and effect of such differences is presented in Note 21 to the consolidated financial statements.

As discussed in Note 3 to the consolidated financial statements, the Trust has changed its method of accounting for financial instruments in 2008 and 2007 due to the adoption of new Canadian standards on the presentation of financial instruments.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 26, 2009 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

/s/ KPMG

Chartered Accountants

Calgary, Canada
March 26, 2009 except as to note 6 and note 21(k) which is as of June 22, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterra Energy Corp., as Administrator of Enterra Energy Trust

We have audited Enterra Energy Trust's ("the Trust") internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards, the consolidated balance sheets of the Trust as of December 31, 2008 and 2007, and the related consolidated statements of income (loss) and comprehensive income (loss), deficit and cash flows for each of the years in the three-year period ended December 31,

2008. With respect to the years ended December 31, 2008 and 2007, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 26, 2009, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG

Chartered Accountants

Calgary, Canada
March 26, 2009

Enterra Energy Trust
Consolidated Balance Sheets

As at December 31 (in thousands of Canadian dollars)	2008	2007
Assets		
Current assets		
Cash and cash equivalents	13,638	3,554
Accounts receivable (note 13)	46,119	30,391
Prepaid expenses, deposits and other	1,959	2,270
Commodity contracts (note 13)	14,338	607
Future income tax asset (note 12)	-	2,187
	76,054	39,009
Property, plant and equipment (note 4)	491,654	556,778
Long term receivables (note 20)	19,310	4,003
	587,018	599,790
Liabilities		
Current liabilities		
Bank indebtedness (note 6)	95,466	171,953
Accounts payable and accrued liabilities	37,949	35,763
Future income tax liability (note 12)	4,187	-
Commodity contracts (note 13)	-	5,764
Note payable (note 7)	-	711
	137,602	214,191
Convertible debentures (note 9)	113,420	111,692
Asset retirement obligations (note 8)	22,151	29,939
Future income tax liability (note 12)	19,429	24,784
	292,602	380,606
Unitholders' equity (note 10)		
Unitholders' capital	669,667	667,690
Equity component of convertible debentures (note 9)	3,977	3,977
Warrants	-	1,215
Contributed surplus	8,620	4,660
Accumulated other comprehensive income (loss) (note 11)	18,471	(44,978)
Deficit	(406,319)	(413,380)
	(387,848)	(458,358)
	294,416	219,184
	587,018	599,790

Commitments and contingencies (notes 17 and 18)
Subsequent event (note 6)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board:

Signed "Peter Carpenter" Signed "Victor Dusik"
Director Director

Enterra Energy Trust
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
For year ended December 31

(in thousands of Canadian dollars except per unit amounts)	2008	2007	2006
Revenues			
Oil and natural gas	275,497	207,036	244,408
Royalties	(58,350)	(45,365)	(48,288)
	217,147	161,671	196,120
Expenses			
Production	55,846	62,483	48,494
Transportation	2,492	2,340	1,867
General and administrative	15,858	20,414	17,145
Provision for non-recoverable receivables (note 13)	8,522	-	-
Interest expense (note 14)	17,466	22,582	26,717
Financing fees	-	-	5,447
Amortization of deferred financing charges	-	-	11,713
Unit-based compensation expense	4,415	4,128	3,229
Depletion, depreciation and accretion (notes 4 and 8)	99,377	150,701	201,448
Goodwill impairment (note 5)	-	76,463	-
Foreign exchange loss	1,279	546	1,910
	205,255	339,657	317,970
Income (loss) before taxes and non-controlling interest	11,892	(177,986)	(121,850)
Income taxes (note 12)			
Current	344	101	1,324
Future expense (reduction)	4,487	(36,051)	(58,899)
	4,831	(35,950)	(57,575)
Net income (loss) before non-controlling interest	7,061	(142,036)	(64,275)
Non-controlling interest	-	-	(36)
Net income (loss)	7,061	(142,036)	(64,239)
Other comprehensive income (loss)			
Foreign currency translation adjustment (note 11)	63,449	(46,908)	1,930
Comprehensive income (loss)	70,510	(188,944)	(62,309)
Net income (loss) per trust unit (note 10)			
– Basic and diluted	0.11	(2.38)	(1.46)

CONSOLIDATED STATEMENTS OF DEFICIT
(in thousands of Canadian dollars)

Deficit, beginning of year	(413,380)	(240,777)	(85,840)
Change in accounting policy (note 3)	-	1,009	-
Net income (loss)	7,061	(142,036)	(64,239)

Distributions declared	-	(31,576)	(90,698)
Deficit, end of year	(406,319)	(413,380)	(240,777)

See accompanying notes to the consolidated financial statements.

Enterra Energy Trust
Consolidated Statements of Cash Flows
For the year ended December 31

(in thousand of Canadian dollars)	2008	2007	2006
Cash provided by (used in):			
Operating			
Net income (loss)	7,061	(142,036)	(64,239)
Depletion, depreciation and accretion (notes 4 and 8)	99,377	150,701	201,448
Goodwill impairment (note 5)	-	76,463	-
Future income tax expense (reduction) (note 12)	4,487	(36,051)	(58,899)
Amortization of financing charges	548	988	11,713
Commodity contracts (gain) loss (note 13)	(20,072)	16,205	(10,628)
Foreign exchange loss	1,279	951	1,038
Unit-based compensation (note 10)	4,415	4,128	3,229
Financing fees	-	-	5,065
Amortization of marketing contract	-	-	(1,447)
Non-controlling interest	-	-	(36)
Non-cash interest on convertible debentures	1,728	1,339	33
Loss on sale of assets	-	-	59
Cash paid on asset retirement obligations (note 8)	(1,771)	(2,225)	(1,219)
	97,052	70,463	86,117
Changes in non-cash working capital items (note 15)	(5,492)	6,381	(21,632)
	91,560	76,844	64,485
Financing			
Increase in bank indebtedness	-	-	587,818
Repayment of bank indebtedness	(76,487)	(15,495)	(510,353)
Proceeds from (repayment of) notes, net	(742)	878	(3,990)
Distributions paid	-	(39,486)	(90,487)
Issuance of convertible debentures, net of issuancecosts	-	37,514	138,000
Issue of trust units, net of issuance costs (note 10)	(97)	27,438	50,391
Capital lease	-	(1,702)	(878)
Financing fees	-	-	(22,405)
Due to JED Oil Inc.	-	-	(2,009)
Exercise of trust unit options	-	-	1,399
	(77,326)	9,147	147,486
Investing			
Property, plant and equipment additions	(32,891)	(25,066)	(30,918)
Capital expenditure to be recovered (note 20)	(19,976)	(6,724)	-
Repayment of long-term receivable (note 20)	5,049	1,105	-
Proceeds on disposal of property, plant andequipment	39,553	11,349	6,586
Acquisition of Trigger Resources (note 4)	-	(63,257)	-
Acquisition of Oklahoma assets (note 4)	-	-	(182,183)
Changes in non-cash working capital items (note 15)	4,465	(1,778)	(7,645)
	(3,800)	(84,371)	(214,160)
Impact of foreign exchange on cash balances	(350)	(228)	(7,592)
Change in cash and cash equivalents	10,084	1,392	(9,781)
Cash and cash equivalents, beginning of year	3,554	2,162	11,943
Cash and cash equivalents, end of year	13,638	3,554	2,162

See accompanying notes to the consolidated financial statements.

1. Basis of presentation

Enterra Energy Trust (the "Trust") was established in November 2003. The Trust is an open-end unincorporated investment trust governed by the laws of the province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). The purpose of the Trust is to indirectly hold interests in petroleum and natural gas properties, through notes from, and investments in securities of its subsidiaries. The beneficiaries of the Trust are the holders of trust units issued by the Trust (the "unitholders").

These consolidated financial statements include the accounts of the Trust and its subsidiaries (collectively the "Trust" or "Enterra" for purposes of the following notes to the consolidated financial statements). All inter-company accounts and transactions have been eliminated.

2. Significant accounting policies

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

(a) Basis of accounting

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

(b) Cash and cash equivalents

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

(c) Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust to its customers based on contracts which establish the price of products sold and when collection is reasonably assured.

(d) Petroleum and natural gas properties

Enterra follows the "full cost" method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of oil and gas reserves are capitalized into one of two cost centers, Canada or the United States. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells and production equipment.

General and administrative costs are capitalized if they are directly related to development or exploration projects.

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

Repair and maintenance costs are expensed as incurred.

(e) Impairment test

The Trust places a limit on the carrying value of property and equipment, which may be depleted against revenues of future periods (the “ceiling test”). The ceiling test is conducted separately for each cost center, Canada and the United States. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value of the cost center. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of petroleum and natural gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects.

The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(f) Use of estimates

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

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

The amounts recorded for financial derivatives are based on estimates of the price for oil and natural gas in future periods. These estimates are subject to fluctuations in market prices and will impact the consolidated financial statements of future periods.

(g) Depletion and depreciation

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

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

(h) Goodwill

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

(i) Asset retirement obligations

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

(j) Income taxes

Enterra follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized based on the differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Future tax assets are recognized to the extent they are more likely than not to be realized.

The Trust is a taxable entity under the Canadian Income Tax Act and is currently taxable only on income that is not distributed or distributable to the unitholders. In 2007, changes to Canadian tax legislation resulted in a new tax on distributions from publicly traded income trusts commencing in 2011. This has resulted in the recognition of future income taxes at the trust level. Prior to 2007, future income taxes were recognized only on the corporate subsidiaries of the Trust.

(k) Commodity contracts

Enterra uses commodity contracts such as collars, floors, calls and swaps to manage its exposure to commodity price fluctuations. Actual amounts received, or paid, on the settlement of the commodity contracts are recorded in oil and gas revenue. Enterra uses the fair value method for reporting commodity contracts whereby a derivative financial instrument is recorded as an asset or a liability on the balance sheet, and changes in the fair value during a financial period are recorded in oil and natural gas revenue.

(l) Trust unit compensation plans

Enterra has multiple unit based compensation plans, which are described in note 10. Compensation expense associated with each unit based compensation plan is recognized in earnings over the vesting period of the plan with a corresponding increase in contributed surplus. Any consideration received upon the exercise of the unit based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in unitholders' capital. Compensation expense is based on the estimated fair value of the unit based compensation at the date of grant.

(m) Foreign currency transactions

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

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

(n) Per unit amounts

Per unit amounts are calculated using the weighted average number of units outstanding. The Trust follows the treasury stock method to determine dilutive effect of options, warrants and other dilutive instruments. Under the treasury stock method, only "in-the-money" dilutive instruments impact the diluted calculations. Convertible debentures are included in the calculation of diluted income per unit based on the number of trust units that would be issued on conversion of the convertible debentures at the end of the year and an add-back of the associated interest expense for the year as long as the conversion results in a dilution to the Trust.

(o) Environmental liabilities

The Trust records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Any amounts expected to be recovered from others, including insurance coverage, are recorded as an asset separate from the associated liability.

(p) Non-controlling interest

Enterra had, through its subsidiaries four types of exchangeable shares that were classified as non-controlling interest on the consolidated balance sheets. Income after tax attributable to these exchangeable shares is deducted from net earnings of Enterra on the consolidated statement of loss.

When the Enterra Energy Corp. exchangeable shares were exchanged for trust units, they were measured at the fair value of the trust units issued. The amounts in excess of the carrying value of exchangeable shares were allocated to property, plant and equipment, to the extent possible, with any excess amounts being allocated to goodwill. When the other exchangeable shares, which were initially recorded at estimated fair value, were exchanged for trust units, they were measured at their carrying value.

(q) Deferred financing charges

Prior to January 1, 2007, deferred financing charges were amortized over the lives of the related debt. Subsequent to January 1, 2007 transactions costs are recorded net of the related financing and amortized using the effective interest method.

(r) Comparative figures

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

3. Adoption of new accounting standards

Adopted in 2008

Financial instrument and capital disclosures

The CICA issued the following accounting standards effective for fiscal years beginning on or after January 1, 2008: Section 1535 “Capital Disclosures”, Section 3862 “Financial Instruments – Disclosures” and Section 3863 “Financial Instruments – Presentation”.

Section 1535 “Capital Disclosures” requires Enterra to provide disclosures about the capital of Enterra and how it is managed.

Section 3862 “Financial Instruments – Disclosures” and Section 3863 “Financial Instruments – Presentation” replace Section 3861 “Financial Instruments - Disclosure and Presentation”, revising disclosures related to financial instruments, including hedging instruments, and carrying forward unchanged presentation requirements.

The adoption of these new accounting standards did not impact the amounts reported in the financial statements of Enterra; however, it did result in expanded note disclosure (see note 13 and note 16).

Adopted in 2007

Effective January 1, 2007, Enterra adopted new Canadian accounting standards and related amendments to other standards on financial instruments.

i. Financial instruments – recognition and measurement

The Trust's cash and cash equivalents, investments in marketable securities and commodity contracts have been classified as held for trading and are recorded at fair value on the balance sheet. Changes in the fair value of these instruments are recorded in net income. All other financial instruments are recorded at cost or amortized cost, subject to impairment reviews. At December 31, 2008 and 2007 there were no held to maturity or available for sale financial assets. Enterra has not voluntarily elected to record any financial instruments as held for trading.

The Trust’s physical purchase and sale contracts have been designated as derivatives and are recorded at estimated fair value on the balance sheet with changes in estimated fair value each period charged to earnings.

Embedded derivatives that do not meet certain exemptions are also required to be separately accounted for at fair value with changes in fair value included in earnings. Enterra elected January 1, 2007 as the effective date for assessing embedded derivatives. There are no significant embedded derivatives that required separate accounting for the years ended December 31, 2008 and 2007.

Transaction costs on the convertible debentures are presented net of the related debt and amortized to earnings using the effective interest method.

ii. Comprehensive income

Comprehensive income includes net loss, holding gains and losses on available for sale investments, gains and losses on cash flow hedges and foreign currency gains and losses relating to self-sustaining foreign operations, all of which are not included in the calculation of earnings until realized.

The impact of adopting these standards at January 1, 2007 were as follows:

(in thousands of Canadian dollars)	As reported	Adjustments		As adjusted
Assets:				
Current assets	55,166	2,637	(a)(b)	57,803
Deferred finance charges	4,676	(4,676)	(b)	-
Liabilities:				
Convertible debentures	78,974	(3,481)	(b)	75,493
Future income tax	40,340	432	(a)	40,772
Unitholders' equity				
Cumulative translation adjustment	1,930	(1,930)	(c)	-
Deficit	(240,777)	1,009	(a)	(239,768)
Accumulated other comprehensive income	-	1,930	(c)	1,930

Notes:

(a) Physical purchase and sale contracts have been designated as derivatives and are measured at their estimated fair value of $1.4 million with the offset, as required on adoption of the new standards, included in retained earnings ($1.0 million net of income taxes).

(b) Convertible debenture financing costs of $3.5 million, previously classified as deferred financing charges, are reclassified to convertible debentures. Financing fees of $1.2 million have been reclassified to prepaid expenses and are amortized over the term of the related credit facilities.

(c) The cumulative translation adjustment is reclassified to accumulated other comprehensive income. The cumulative translation adjustment as at December 31, 2006 was reclassified to accumulated other comprehensive income as required by the new standards.

Future accounting policies to be adopted

When Enterra has not adopted a new accounting standard that has been issued but not yet effective, the entity is required to disclose (a) this fact; and (b) known or reasonably estimable information relevant to assessing the possible impact that application of the new standard will have on the Trust's financial statements in the period of initial application.

In December 2008, the CICA issued a new accounting standard for "Business Combinations". This standard outlines new guidance which states that the purchase price is to be based on trading data at the closing date of the acquisition, not the announcement date of the acquisition, and that most acquisition costs are to be expensed as incurred. The new standard becomes effective on January 1, 2011 and early adoption is permitted. This standard will require the Trust to change its accounting policies for any new business combinations completed after the standard is adopted.

In February 2008, the Canadian Institute of Chartered Accountants confirmed that Canadian GAAP for publicly accountable enterprises will be converted to International Financial Reporting Standards (IFRS) on January 1, 2011. This change in GAAP will be effective for years beginning January 1, 2011.

In December 2007, the SEC announced that the U.S. GAAP reconciliations requirement will be waived for Foreign Private Issuers who file financial statements prepared in accordance with IFRS for years beginning on or after January 1, 2009.

The Trust is currently assessing the impact of the conversion from Canadian GAAP to IFRS on the results of operations, financial position and disclosures. A project team has been set up to manage this transition and to ensure successful implementation within the required timeframe. The Trust will provide disclosures of key elements of its plan and progress on the project as the information becomes available during the transition period.

4. Property, plant and equipment

(in thousands of Canadian dollars)	2008	2007
Oil and natural gas properties, including production and processing equipment	1,107,992	1,069,891
Accumulated depletion and depreciation	616,338	513,113
Net book value	491,654	556,778

At December 31, 2008 costs of undeveloped land and seismic of $11.8 million (2007 - $18.6 million; 2006 - $25.9 million) were excluded from and $3.0 million (2007 - $11.8 million; 2006 - $8.0 million) of future development costs were added to the Canadian cost centre for purposes of the calculation of depletion expense. At December 31, 2008 costs of undeveloped land of $11.9 million (2007 - $7.8 million; 2006 - $16.8 million) were excluded from and $3.7 million (2007 - $3.0 million; 2006 - $3.0 million) of future development costs were added to the U.S. cost centre for purposes of the calculation of depletion expense.

Depletion and depreciation expense related to the Canadian and the U.S. cost centers in 2008 were $61.7 million and $35.8 million respectively (2007 – $77.7 million and $44.5 million; 2006 – $90.7 million and $42.6 million).

During 2008 $1.8 million of general and administrative expenses and $0.6 million (including future taxes of $0.2 million) of unit-based compensation were capitalized and included in the cost of the petroleum and natural gas properties (2007 - $1.1 million and nil; 2006 – nil and nil, respectively).

The following table summarizes the benchmark prices used in the ceiling test calculation. The petroleum and natural gas prices are based on the December 31, 2008 commodity price forecast of Enterra's independent reserve engineers.

Year	WTI Oil ($U.S./bbl)	Foreign Exchange Rate (US$/CAD)	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/GJ)	Henry Hub ($U.S./Mmbtu)
2009	60.00	0.850	69.60	7.40	7.25
2010	71.40	0.850	83.00	8.00	7.75
2011	83.20	0.900	91.40	8.45	8.60
2012	90.20	0.950	93.90	8.80	9.35
2013	97.40	1.000	96.30	9.05	10.10
2014	99.40	1.000	98.30	9.25	10.30
Escalate Thereafter	Average 2% per year	1.000	Average 2% per year	Average 2% per year	Average 2% per year

Enterra completed ceiling test calculations for the Canadian and U.S. cost centers at December 31, 2008 to assess the recoverability of costs recorded in respect of the petroleum and natural gas properties. The ceiling test did not result in a write down of the Canadian cost center or the U.S. cost center (2007 - $26.3 million write down in the Canadian cost center and no write down in the U.S. cost center; 2006 - $48.8 million write down in the Canadian cost center and $17.2 million write down in the U.S. cost center). Ceiling test write downs are included in depletion expense.

Acquisition of Trigger Resources

On April 30, 2007 Enterra acquired all of the issued and outstanding shares of Trigger Resources Ltd. ("Trigger Resources") for total consideration of $63.3 million. Trigger was acquired to provide additional exposure to oil and gas developments in Saskatchewan and expand the Trust's undeveloped acreage.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

(in thousands of Canadian dollars)
Allocation of purchase price:

Current assets	$	2,806
Property, plant and equipment		81,382
Current liabilities		(2,781)
Future income tax liability		(15,576)
Asset retirement obligations		(2,574)
	$	63,257

(in thousands of Canadian dollars)
Consideration:

Cash	$	62,965
Transaction costs		292
	$	63,257

Acquisition of Oklahoma Assets

During 2006, Enterra acquired oil and natural gas properties located in Oklahoma ("Oklahoma Assets"). The acquisition was completed in four stages.

Prior to closing the acquisitions, the Trust acquired $49.7 million of notes payable by the primary vendors of the Oklahoma Assets; as a result the vendors owed the Trust $49.7 million. The primary vendors repaid the Trust $38.5 million of the notes upon closing the second stage of the acquisition of the Oklahoma Assets. The acquisition of the notes, by the Trust, was financed with a US$50.0 million senior bridge credit facility.

On January 18, 2006, the Trust closed the first stage of the acquisition of the Oklahoma Assets. The results of the operations of the assets acquired are included in the Trust's consolidated financial statements as of January 18, 2006.

On March 21, 2006, the Trust closed the second stage of the acquisition of the Oklahoma Assets. Along with the second stage, the Trust acquired the operating company of the Oklahoma Assets. The results of operations of the assets acquired and the operating company are included in the Trust's consolidated financial statements as of March 21, 2006.

On April 4, 2006, the Trust closed the third stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 4, 2006.

On April 18, 2006, the Trust closed the fourth stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 18, 2006.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:

Current assets	$	6,412
Property, plant and equipment		352,999
Current liabilities		(25,355)

Financial derivatives	(485)
Debt	(24,036)
Asset retirement obligations	(1,926)
	$ 307,609

Cost of acquisitions:	
Cash paid and payable	$ 181,044
Transaction costs	10,040
5,685,028 trust units	116,525
	$ 307,609

The value assigned to each trust unit of $20.51 (US$17.70) was based on the weighted average trading price immediately prior to the measurement date. The acquisition provides cash flows from currently producing assets and provides the opportunity for the exploitation of the undeveloped lands.

As a result of adjustments to the purchase price, as determined by the purchase and sale agreement, Enterra owed $1.4 million (US$1.5 million) to the vendors as at December 31, 2007 ($8.9 million (US$7.6 million) in 2006).

5. Goodwill

During 2007 Enterra recorded a goodwill impairment loss of $76.5 million (2006 – nil) relating to the Canadian reporting unit. The goodwill impairment loss was a result of the Enterra's net book value exceeding Enterra's market capitalization.

6. Debt

(in thousands of Canadian dollars)	2008	2007
Revolving credit facility	90,000	129,500
Operating credit facility	5,466	2,116
Second-lien facility	-	40,000
Other	-	337
Bank indebtedness	95,466	171,953

On June 25, 2008 Enterra entered into credit facilities with its banking syndicate that includes revolving and operating credit facilities which had a borrowing capacity of $135.0 million and a second-lien credit facility with a maximum of $12.0 million at December 31, 2008. The second-lien facility was undrawn and was cancelled in June 2009 at Enterra's option. The Trust's Bank Syndicate completed a mid-year borrowing base review in June 2009 and adjusted the borrowing base to $110.0 million. The next scheduled annual review of the borrowing base is anticipated to be completed in Q1 2010 and there may be an interim review in the latter part of 2009. Changes to the amount of credit available may be made after these reviews are completed. The revolving and operating credit facilities are secured with a first priority charge over the assets of Enterra. Borrowings under the revolving and operating credit facilities at December 31, 2008 were $95.5 million with no borrowings under the second-lien facility. The maturity date of the revolving and operating credit facilities is June 25, 2010 and should the lenders decide not to renew the facility, the debt must be repaid on June 25, 2011.

Interest rates for the credit facilities are set quarterly according to a grid based on the ratio of bank debt with respect to cash flow with the lowest rates in the grid being Canadian dollar BA ("Bankers Acceptance") or U.S. dollar LIBOR rates plus a margin of 3.00%, effective with the June 2009 renewal of the credit facilities. As at December 31, 2008, borrowings under the revolving and operating credit facilities were at Canadian dollar BA or U.S. dollar LIBOR rates plus a margin of 1.25%, or Canadian or U.S. prime rates plus a margin of 0.25% depending on the form of borrowing.

As at December 31, 2008 all borrowings under the facilities were denominated in Canadian dollars and interest was being accrued at a rate of 3.75% per annum. At December 31, 2008, letters of credit totaling $0.5 million reduced the amount that can be drawn under the operating credit facility.

The second-lien credit facility was a non-revolving credit facility and is subordinated to the revolving and the operating credit facilities and as at December 31, 2008 had not been drawn down. The facility bore interest according to a grid similar to the above and as of December 31, 2008 borrowings were at Canadian dollar BA or

U.S. dollar LIBOR rates plus a margin of 3.50%, or Canadian or U.S. prime rates plus a margin of 2.50% depending on the form of borrowing.

During 2008, Enterra repaid the other debt which had a balance of $0.3 million at December 31, 2007.

Enterra is required to maintain several financial and non-financial covenants and an interest coverage ratio of 3.0:1.0 as calculated pursuant to the terms of the credit agreement. In addition, distributions are limited to 100% of cash flow, as defined in the credit agreement, once distributions are permitted to be paid pursuant to the restrictions under the second-lien facility. The Trust is in compliance with the terms and covenants of the credit facilities as at December 31, 2008.

At December 31, 2007, Enterra had a revolving extendible credit facility of $140.0 million and a $40.0 million second-lien non-revolving credit facility. The credit facilities were further amended subsequent to December 31, 2007 such that Enterra had available $129.5 million revolving extendible facility, an $18.5 million operating facility and a $40.0 million second-lien non-revolving facility.

7. Note payable and capital lease

Note payable
Enterra had a note payable that was for the purchase of certain natural gas interests in the U.S. which was repaid in full during the first quarter of 2008.

Capital lease
During 2007 and 2006, the capital lease bore a rate of interest of 8.6% and was repayable in monthly installments of $0.1 million, including interest with a final payment of $1.0 million. The lease term was for 60 months ending on October 1, 2007. Interest expense on the lease in 2007 was $0.2 million (2006 - $0.2 million).

8. Asset retirement obligations

The asset retirement obligations were estimated by management based on Enterra's working interests in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At December 31, 2008, the asset retirement obligation is estimated to be $22.2 million (2007 – $29.9 million), based on a total future liability of $39.2 million (2007 - $49.4 million). These obligations will be settled at the end of the useful lives of the underlying assets, which currently averages six years, but extends up to 18 years into the future. This amount has been calculated using an inflation rate of 2.0% and discounted using a credit-adjusted interest rate of 8.0% to 10.0%.

The following table reconciles the asset retirement obligations:

(in thousands of Canadian dollars)	2008	2007	2006
Balance, beginning of year	29,939	28,447	24,323
Acquisitions	-	2,574	1,926
Additions	223	2,108	1,281
Revisions	-	-	2,000
Accretion expense	1,892	2,182	2,166
Dispositions	(8,712)	(2,130)	-
Costs incurred	(1,771)	(2,225)	(3,178)

Foreign exchange	580	(1,017)	(71)
Balance, end of year	22,151	29,939	28,447

9. Convertible debentures

On April 26, 2007, the Trust issued $40.0 million of convertible debentures with a face value of $1,000 per convertible debenture that mature on June 30, 2012, bear interest at 8.25% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to the bank credit facilities. The convertible debentures are convertible at the option of the holder into trust units at any time prior to the maturity date at the conversion price of $6.80 per trust unit. During 2008 and 2007, there were no conversions of the debentures.

On November 21, 2006, the Trust issued $138.0 million of convertible debentures that mature on December 31, 2011, bear interest at 8% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to the bank credit facilities. The convertible debentures are convertible at the option of the holder into trust units at any time prior to the maturity date at the conversion price of $9.25 per trust unit. During 2008 and 2007, there were no conversions of the debentures.

At the option of the Trust, the repayment of the principal portion of the convertible debentures may be settled in trust units. The number of trust units issued upon redemption by the Trust will be calculated by dividing the principal by 95% of the weighted average trading price of trust units. The 8.25% convertible debentures are not redeemable on or before June 30, 2010 (8% - December 31, 2009). On or after July 1, 2010 and prior to maturity, the convertible debentures may be redeemed in whole or in part from time to time at the option of the Trust on not more than 60 days and not less than 30 days notice, at a redemption price of $1,050 per convertible debenture on or after July 1, 2010 (8% - January 1, 2010) and, on or before June 30, 2011 (8% - January 1, 2010), at a redemption price of $1,025 per convertible debenture and on or after July 1, 2011 (8% - January 1, 2011) and prior to maturity, in each case, plus accrued and unpaid interest thereon, if any. At December 31, 2008, the Trust had $80.3 million in 8% convertible debentures (2007 - $80.3 million) outstanding with an estimated fair value of $50.6 million (2007 - $66.6 million) and $40.0 million in 8.25% convertible debentures (2007 - $40.0 million) outstanding with an estimated fair value of $25.4 million (2007 - $32.0 million).

(in thousands of Canadian dollars)	8% Series	8.25% Series	Total	Equity Component
November 21, 2006 issuance	138,000	-	138,000	-
Portion allocated to equity	(2,387)	-	(2,387)	2,387
Issue costs	-	-	-	(107)
Accretion	33	-	33	-
Converted to trust units	(56,672)	-	(56,672)	(953)
Balance, December 31, 2006	78,974	-	78,974	1,327
April 28, 2007 issuance	-	40,000	40,000	-
Portion allocated to equity	-	(2,765)	(2,765)	2,765
Issue costs reclassified against carrying value (note 3)	(3,481)	-	(3,481)	-
Issue costs	(305)	(2,069)	(2,374)	(115)
Accretion	844	494	1,338	-
Balance, December 31, 2007	76,032	35,660	111,692	3,977
Accretion	930	798	1,728	-
Balance, December 31, 2008	76,962	36,458	113,420	3,977

The unsecured convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the value of the conversion option. If the debentures are converted to trust units, the debt and equity components are transferred to unitholders' capital. The debt balance associated with the convertible debentures accretes over time to the amount owing on maturity with such increases reflected as non-cash interest expense in the consolidated statement of income.

10. Unitholders' equity

Authorized trust units
An unlimited number of trust units may be issued.

The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $0.1 million per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

Issued trust units

(in thousands of Canadian dollars except unit amounts)	Number of Units	Amount
Balance at December 31, 2005	36,504,416	373,761
Issued for cash pursuant to private placements	657,500	12,544
Issued on acquisition of Oklahoma Assets	5,685,028	116,525
Issued for cash pursuant to prospectus offering	4,979,500	40,334
Issued on conversion of convertible debentures	6,234,483	57,625
Issued as financing fees on bridge credit facilities	116,054	2,077
Issued for exchangeable shares	1,779,184	36,502
Issued under restricted unit plan	41,805	579
Issued on exercise of options	99,905	1,427
Unit issue costs	-	(6,240)
Balance at December 31, 2006	56,097,875	635,134
Issued for cash pursuant to prospectus offering	4,945,000	29,176
Issued as financing fees related to the retirement of the 2006 bridge credit facilities	50,000	515
Issued for exchangeable shares	104,429	1,940
Issued under restricted unit plan	238,591	2,663
Unit issue costs	-	(1,738)
Balance at December 31, 2007	61,435,895	667,690
Issued under restricted unit plan	723,092	2,074
Unit issue costs	-	(97)
Balance at December 31, 2008	62,158,987	669,667

Warrants

In April 2005 as part of an agreement to issue equity, the Trust granted warrants to Kingsbridge Capital Limited to purchase 301,000 trust units. The warrants had a three-year term that expired in April 2008. The exercise price of the warrants was initially US$25.77 per trust unit and was reduced each month by the amount of the Trust's distribution for such month on the trust units, provided that the price did not decrease below US$21.55 per trust unit. No warrants were exercised from this issuance.

Contributed surplus

(in thousands of Canadian dollars)	
Balance at December 31, 2005	573
Trust unit option based compensation	1,294
Restricted and performance unit compensation	1,935
Transfer to trust units on restricted and performance unit exercises	(579)
Transfer to trust units on option exercises	(28)
Balance at December 31, 2006	3,195
Trust unit option based compensation	1,300
Restricted and performance unit compensation	2,828
Transfer to trust units on restricted and performance unit exercises	(2,663)
Balance at December 31, 2007	4,660
Trust unit option based compensation	110
Restricted and performance unit compensation	4,709
Transfer to trust units on restricted and performance unit exercises	(2,074)
Expired warrants	1,215
Balance at December 31, 2008	8,620

Trust unit options

Enterra has granted trust unit options to its directors, officers and employees. Each trust unit option permits the holder to purchase one trust unit at the stated exercise price. All options vest over a 1 to 3 year period and have a term of 4 to 5 years. At the time of grant, the exercise price is equal to the market price. The forfeiture rate is estimated to be 60%. The following options have been granted:

(in Canadian dollars, except for number of options)	2008		2007	
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Options outstanding, beginning of year	1,474,334	$ 14.51	1,481,000	$ 20.28
Options granted	210,000	2.81	485,000	2.64
Options forfeited	(642,334)	21.65	(491,666)	20.08
Options outstanding, end of year	1,042,000	7.75	1,474,334	14.51
Options exercisable at end of year	685,336	$ 8.45	710,333	$ 17.14

(in Canadian dollars, except for number of options)

Exercise price range	Number of options	Weighted average exercise price	Weighted average remaining contract life in years	Number of options exercisable	Weighted average price of exercisable options
$1.65 to $2.81	660,000	$2.02	2.96	410,000	$1.96
$15.33 to $19.85	311,000	16.38	2.26	208,002	16.38
$20.12 to $26.80	71,000	23.27	1.31	67,334	23.44
	1,042,000	$7.75	2.64	685,336	$8.45

Estimated fair value of stock options

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

	2008	2007	2006
Weighted-average fair value of options granted ($/option)	0.70	0.96	1.07
Risk-free interest rate (%)	2.5	4.7	4.2
Estimated hold period prior to exercise (years)	4	4	5
Expected volatility (%)	90	77	45
Expected cash distribution yield (%)	-	1	14

Restricted and performance units

Enterra has granted restricted and performance units to directors, officers, and employees. Restricted units vest over a contracted period ranging from vesting on grant to 3 years and provide the holder with trust units on the vesting dates of the restricted units. The units granted are the product of the number of restricted units times a multiplier. The multiplier starts at 1.0 and is adjusted each month based on the monthly distribution of the Trust divided by the five-day weighted average price of the trust units based on the New York Stock Exchange for the period preceding the distribution date. Performance units vest at the end of two years and provide the holder

with trust units based on the same multiplier as the restricted units as well as a payout multiplier. The payout multiplier ranges between 0.0 and 2.0 based on the Trust's total unitholder return compared to its peers. The forfeiture rate is estimated to be 16% for 2008 and 2007. As at December 31, 2008 and 2007 the payout multiplier was estimated to be nil based on the Enterra's total unitholder return compared to its peers.

The following restricted and performance units have been granted:

	Number of restricted units	Weighted-average grant date fair value	Number of performance units	Weighted-average grant date fair value
Units outstanding, December 31, 2005	-	$ -	-	$ -
Granted	479,466	14.90	215,119	15.06
Vested	(44,375)	15.08	-	-
Forfeited	(11,236)	15.66	(2,171)	15.66
Units outstanding, December 31, 2006	423,855	$ 14.91	212,948	$ 15.41
Granted	1,045,507	3.53	363,940	3.20
Vested	(215,383)	12.76	-	-
Forfeited	(196,496)	11.22	(122,717)	13.46
Units outstanding, December 31, 2007	1,057,483	$ 4.77	454,171	$ 6.29
Granted	2,070,683	3.77	-	-
Vested	(718,111)	3.99	-	-
Forfeited	(130,269)	4.37	(279,773)	7.61
Units outstanding, December 31, 2008	2,279,786	$ 4.13	174,398	$ 4.17

The estimated value of the restricted units and performance units is based on the trading price of the trust units on the grant date. For performance units the compensation cost is adjusted for the estimated payout multiple, which at December 31, 2008 and 2007 was nil.

Reconciliation of earnings per unit calculations

For the year ended December 31, 2008

(in thousands of Canadian dollars except units and per unit amounts)	Net Income	Weighted Average Units Outstanding	Per Unit
Basic	7,061	61,660,971	$ 0.11
Dilution effect from:			
Restricted trust units		1,173,141	
Trust unit options		177,433	
Diluted	7,061	63,011,545	$ 0.11

For the year ended December 31, 2007

(in thousands of Canadian dollars except units and per unit amounts)	Net Loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	(142,036)	59,766,567	$ (2.38)

For the year ended December 31, 2006

(in thousands of Canadian dollars except units and per unit amounts)	Net Loss	Weighted Average Units Outstanding	Per Unit
Basic and diluted	(64,239)	44,141,688	$ (1.46)

For the calculation of the weighted average number of diluted units outstanding for 2008, 382,000 options, 174,398 performance units and all convertible debentures and warrants were excluded, as they were anti-dilutive to the calculation. For 2007 and 2006, all options, restricted units, performance units, convertible debentures and warrants were excluded as they were anti-dilutive to the calculation.

Trust unit savings plan

Enterra established a trust unit savings plan whereby it will match an employee's contributions to the plan to a maximum of 9.0% of their salary. Both the contributions of the employee and the Trust were used to purchase trust units on the Toronto Stock Exchange. During 2008 the Trust expensed approximately $0.4 million (2007 - $0.4 million; 2006 - $0.3 million) relating to its contributions to the plan.

11. Accumulated other comprehensive income (loss)

(in thousands of Canadian dollars)	2008	2007	2006
Opening balance	(44,978)	1,930	-
Cumulative translation of self-sustaining operations	61,378	(48,986)	1,082
Foreign exchange loss realized	2,071	2,078	848
Balance at December 31	18,471	(44,978)	1,930

Accumulated other comprehensive income (loss) is comprised entirely of currency translation adjustments on the U.S. operations.

12. Income taxes

The income tax provision differs from the amount of tax expense calculated by applying federal and provincial statutory tax rates to the earnings (loss) before taxes as follows:

(in thousands of Canadian dollars)	2008	2007	2006
Income (loss) before income taxes	11,892	(177,986)	(121,850)
Combined federal and provincial income tax rate	29.7%	32.1%	34.50%

Computed income tax expense (reduction)	3,532	(57,169)	(42,038)
Increase (decrease) resulting from:			
Interest component of trust distributions	-	(10,139)	(13,788)
Goodwill impairment	-	24,560	-
Other non-deductible items	5,406	1,880	1,418
Difference between U.S. and Canadian tax rates	2,528	(2,076)	(1,494)
Change in estimated pool balances	(3,309)	567	-
Change in tax rates	(4,950)	2,447	(6,669)
Other	1,280	3,499	2,505
Capital tax	344	481	341
Non-deductible crown charges	-	-	3,614
Resource allowance	-	-	(1,464)
	4,831	(35,950)	(57,575)

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

(in thousands of Canadian dollars)	2008	2007
Future income tax assets:		
Non-capital loss carry-forwards and other	42,867	47,475
Valuation allowance on non-capital losses	(16,612)	(9,451)
Asset retirement obligations	6,123	8,786
Attributed Canadian royalty income	1,317	1,317
Commodity contracts	-	1,516
Financing charges	480	850
	34,175	50,493
Future income tax liabilities:		
Property, plant and equipment	(53,604)	(72,911)
Commodity contracts	(4,187)	(179)
Net future income tax liability	(23,616)	(22,597)

Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken, amongst Canadian and U.S. subsidiaries, totaled $61.3 million (2007 – $104.4 million) and expire from 2009 to 2025.

The effect of the enactment of the SIFT tax on the future tax provision for the year ended December 31, 2007 was not significant.

13. Risk management

(a) Fair value of financial instruments

The fair value of financial instruments is the amount of consideration that would be agreed upon in an arm’s length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted market prices, as appropriate, in the most advantageous market for that instrument to which the Trust had immediate access. Where quoted market prices are not available, Enterra uses the closing price of the most recent transaction for that instrument. In the absence of an active market, the Trust determines fair values based on prevailing market rates for instruments with similar characteristics.

(i) Convertible debentures

At December 31, 2008 the convertible debentures have a carrying value of approximately $113.4 million (December 31, 2007 - $111.7 million), excluding the amount allocated to the equity component and a fair value of approximately $76.0 million (December 31, 2007 - $98.6 million). The fair value of the convertible debentures is determined based on market prices at December 31, 2008 and December 31, 2007 respectively.

(ii) Derivative commodity contracts

The Trust's financial and physical commodity contracts are recorded at estimated fair value with changes in estimated fair value each period charged to earnings. Fair values are determined based on valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

The fair value of the derivatives at December 31, 2008, is estimated to be an asset of $14.3 million (December 31, 2007 – net liability of $5.2 million). Included in the oil and natural gas revenues is an unrealized gain on financial derivatives of $20.2 million for 2008 (2007 - $16.8 million loss). Included in production expenses for 2008 is an unrealized loss of $0.2 million (2007 – $0.4 million)

(iii) Other financial instruments

Cash and cash equivalents have been classified as held for trading and are recorded at fair value on the balance sheet. Changes in the fair value are recorded in net earnings. The fair value of the financial instruments, except the convertible debentures, cash and cash equivalents and commodity contracts approximate their carrying value as they are short term in nature or bear interest at floating rates.

(b) Financial risk management

In the normal course of operations, Enterra is exposed to various market risks such as liquidity, credit, interest rate, foreign exchange and commodity risk. To manage these risks, management determines what activities must be undertaken to minimize potential exposure to risks. The objectives of Enterra to managing risk are as follows:

Objectives:

- maintaining sound financial condition;
- financing operations; and
- ensuring liquidity in the Canadian and U.S. operations.

In order to satisfy the objectives above, Enterra has adopted the following policies:

- prepare budget documents at prevailing market rates to ensure clear, corporate alignment to performance management and achievement of targets;
- recognize and observe the extent of operating risk within the business;
- identify the magnitude of the impact of market risk factors on the overall risk of the business and take advantage of natural risk reductions that arise from these relationships; and
- utilize financial instruments, including derivatives to manage the remaining residual risk to levels that are within the risk tolerance of the Trust.

The policy objective with respect to the utilization of derivative financial instruments is to selectively mitigate the impact of fluctuations in commodity prices. The use of any derivative instruments is carried out in accordance with approved limits as authorized by the board of directors and imposed by external financial covenants. It is not the intent of Enterra to use financial derivatives or commodity instruments for trading or speculative purposes and no financial derivatives have been designated as accounting hedges.

Enterra’s process to manage changes in risks has not changed from the prior period.

(i) Market risks

Oil and gas commodity price risks
Enterra is exposed to fluctuations in natural gas and crude oil prices. Enterra has entered into commodity contracts and fixed price physical contracts to minimize the exposure to fluctuations in crude oil and natural gas prices. At December 31, 2008, the following financial derivative contracts are outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Floor	Gas	8.00 ($/GJ)	3,000 GJ	November 1, 2008 – March 31, 2009
Floor	Gas	9.00 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	9.50 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Gas	10.00 (US$/mmbtu)	5,000 mmbtu	November 1, 2008 – March 31, 2009
Floor	Oil	72.00 (US$/bbl)	1,000 bbl	January 1, 2009 – December 31, 2009
Sold Call	Oil	91.50 (US$/bbl)	500 bbl	July 31, 2009 – December 31, 2009

Enterra did not have any fixed price oil or gas physical contracts as at December 31, 2008.

Electricity commodity price risks
The Trust is subject to electricity price fluctuations in its operations and it manages this risk by entering into forward fixed rate electricity derivative contracts on a portion of its electricity requirements. The Trust's outstanding electricity derivative contracts as at December 31, 2008 are summarized below.

Fixed purchase	Power (Alberta)	62.90 (Cdn$/Mwh)	72 Mwh	July 1, 2007 – December 31, 2009

The gains (losses) during the year from the commodity contracts are summarized in the table below.

(in thousands of Canadian dollars)	Years ended December 31		
	2008	2007	2006
Realized commodity contract gain	1,915	6,249	12,408
Unrealized commodity contract gain (loss)	20,072	(16,205)	10,628
Net gain (loss) on commodity contracts	21,987	(9,956)	23,036

The following sensitivities show the impact to pre-tax net income for the year ended December 31, 2008 related to commodity contracts of the respective changes in crude oil prices, natural gas and electricity.

	Increase (decrease) to pre-tax net income	
(in thousands of Canadian dollars)	Decrease in market price ($1.00 per bbl and $0.50 per mcf)	Increase in market price ($1.00 per bbl and $0.50 per mcf)
Crude oil derivative contracts (bbl)	413	(413)

Natural gas derivative contracts (mcf)	987	(987)
	$1.00 per Mwh decrease in market price	$1.00 per Mwh increase in market price
Electricity derivative contracts (Mwh)	(32)	32

Foreign exchange currency risks

Enterra is exposed to foreign currency risk as approximately 45% of its production is from the U.S. division. In addition, the Canadian division has derivative financial instruments denominated in U.S. dollars. Enterra has not entered into any derivative contracts to mitigate its currency risks as at December 31, 2008.

Changes in the U.S. to Canadian foreign exchange rates with respect to the U.S. division affect other comprehensive income as the division is considered a self-sustaining foreign operation. The following financial instruments were denominated in U.S. dollars:

(in thousands of dollars)	Canadian division (in U.S. dollars)	U.S. division (in U.S. dollars)
Cash and cash equivalents	7,830	1,295
Accounts receivable	4,977	26,893
Commodity contracts	10,963	-
Accounts payable	(1,596)	(9,935)
Net exposure	22,174	18,253
Effect of a $0.02 increase in U.S. to Cdn exchange rate:	-	-
Increase (Decrease) to pre-tax net income	443	-
Increase (Decrease) to other comprehensive income	-	365
Effect of a $0.02 decrease in U.S. to Cdn exchange rate:	-	-
Increase (Decrease) to pre-tax net income	(443)	-
Increase (Decrease) to other comprehensive income	-	(365)

Interest rate risk

Interest rate risk arises on the outstanding bank indebtedness that bears interest at floating rates. The results of Enterra are impacted by fluctuations in interest rates as its outstanding bank indebtedness carries floating interest rates. The convertible debentures bear interest at fixed rates.

Enterra has not entered into any derivative contracts to mitigate the risks related to fluctuations in interest rates as at December 31, 2008. The following sensitivities show the impact to pre-tax net income for the period ended December 31, 2008 of the respective changes in interest rates (increase / (decrease)).

	Change to pre-tax net income	
(in thousands of Canadian dollars)	1% decrease in market interest rates	1% increase in market interest rates
Interest on bank indebtedness	1,256	(1,256)

(ii) Credit risk

Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations and arises principally from trade, joint venture receivables, long-term receivables as well as any derivative financial instruments in a receivable position. Enterra does not hold any collateral from counterparties. The maximum exposure to credit risk is the carrying amount of the related amounts receivable.

The significant balances receivable are set out below. Accounts receivable include trade receivables, joint venture receivables and non-aging accounts such as cash calls, taxes receivable and operating advances.

(in thousands of Canadian dollars)	December 31, 2008	December 31, 2007
Accounts receivable – trade	39,178	23,264
Accounts receivable – joint venture	2,882	3,724
Accounts receivable – other (1)	14,340	4,517
Allowance for doubtful accounts	(10,281)	(1,114)
	46,119	30,391
Long-term receivables	19,310	4,003

1) Included in accounts receivable – other is $8.6 million related to the current portion of the receivable from Petroflow Energy Ltd. (note 20).

Should Enterra determine that the ultimate collection of a receivable is in doubt based on the processes for managing credit risk, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enterra subsequently determines an account is uncollectible, the account is written off with a corresponding charge to allowance for doubtful accounts. During 2008 Enterra did provide for an allowance as discussed below.

On July 22, 2008, SemGroup, a midstream and marketing company through which the Trust marketed a portion of the Trust's production, filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. and the Canadian units of SemGroup filed for protection under the Companies' Creditors Arrangement Act. As a result, the Trust has recorded a provision for non-recoverable receivables for the full amount owed by SemGroup of $8.5 million with a corresponding decrease to net income ($6.0 million net of tax).

The aging of accounts receivable is set out below:

(in thousands of Canadian dollars)

As at December 31, 2008	Trade	Joint Venture
Current	25,907	629
Over 30 days	3,582	203
Over 60 days	2,055	283
Over 90 days	7,634	1,767
	39,178	2,882

The credit quality of financial assets that are neither past due nor impaired has been assessed and adequately evaluated for impairment based on historical information about the nature of the counterparties.

Purchasers of the natural gas, crude oil and natural gas liquids of Enterra comprise a substantial portion of accounts receivable. A portion of accounts receivable are with joint venture partners in the oil and gas industry. Enterra takes the following precautions to reduce credit risk:

- the financial strength of the counterparties is assessed;
- the total exposure is reviewed regularly and extension of credit is limited; and
- collateral may be required from some counterparties.

As described in note 20, Enterra has a long-term receivable with a joint venture partner. The credit risk as a result of this arrangement is mitigated by the ability of Enterra to withhold a portion of the joint venture partner's share of production until such time as the amounts receivable are paid or the production withheld exceeds the amounts owed to Enterra.

(iii) Liquidity risks

Liquidity risk is the risk that Enterra will not be able to meet its financial obligations as they come due. Enterra mitigates this risk through actively managing its capital, which it defines as unitholders' equity, convertible debentures, note payable, bank indebtedness and cash and cash equivalents. Management of liquidity risk over the short and longer term, includes continual monitoring of forecasted and actual cash flows to ensure sufficient liquidity to meet financial obligations when due and maintaining a flexible capital management structure. Enterra strives to balance the proportion of debt and equity in its capital structure given its current oil and gas assets and planned investment opportunities.

All financial liabilities have short-term maturities with the exception of the convertible debentures (note 9), as set out below:

Financial Instrument – Liability (in thousands of Canadian dollars)	1 Year	2 Years	3 Years	3-5 Years	Total	Fair Value
Bank indebtedness (1)	-	95,466	-	-	95,466	95,466
Interest on bank indebtedness (2)	3,580	1,790	-	-	5,370	5,370
Convertible debentures	-	-	80,331	40,000	120,331	76,049
Interest on convertible debentures	9,726	9,726	9,726	1,650	30,828	30,828
Accounts payable & accrued liabilities	37,949	-	-	-	37,949	37,949
Total obligations	51,255	106,982	90,057	41,650	289,944	245,662

(1) Assumes the credit facilities are not renewed on June 24, 2009.

(2) Assumes an interest rate of 3.75% (the rate on December 31, 2008).

The repayment terms and maturity dates of the credit facilities of Enterra are disclosed in note 6.

14. Interest expense

During 2008, Enterra's interest expense of $17.5 million (2007 – $22.6 million and 2006 – $26.7 million) was comprised of the following below.

(in thousands of Canadian dollars)	2008	2007	2006
Interest on bank indebtedness	8,362	13,108	25,898
Interest on convertible debentures	11,454	9,963	819
Interest income	(2,350)	(489)	-
	17,466	22,582	26,717

15. Changes in non-cash working capital

(in thousands of Canadian dollars)	2008	2007	2006
Accounts receivable	(15,728)	8,589	1,369
Prepaid expenses, deposits and other	311	979	(175)
Accounts payable and accrued liabilities	2,186	(10,320)	(26,536)
Foreign exchange on working capital	12,204	5,355	(3,935)
Changes in non-cash working capital	(1,027)	4,603	(29,277)
Changes in non-cash operating working capital	(5,492)	6,381	(21,632)
Changes in non-cash investing working capital	4,465	(1,778)	(7,645)

During the year ended December 31, 2008 the Trust paid interest of $15.2 million (2007 - $20.3 million; 2006 – $26.5 million) and taxes of $0.3 million (2007 – $0.5 million; 2006 – $2.9 million).

16. Capital disclosures

The capital structure of Enterra consists of unitholders' equity, convertible debentures, note payable, bank indebtedness and cash and cash equivalents as noted below.

(in thousands of Canadian dollars)	December 31, 2008	December 31, 2007
Components of capital:		
Unitholders' equity	294,416	219,184
Convertible debentures	113,420	111,692
Note payable	-	711
Bank indebtedness	95,466	171,953
Less:		
Cash and cash equivalents	(13,638)	(3,554)
	489,664	499,986

The objectives of Enterra when managing capital are:

- to reduce debt, with the long term goal to improve the balance sheet;
- to manage capital in a manner which balances the interest of equity and debt holders;
- to manage capital in a manner that will maintain compliance with its financial covenants; and
- to maintain a capital base so as to maintain investor, creditor and market confidence and to sustain future exploration and development.

Enterra manages its capital structure as determined by management and approved by the board of directors. Adjustments are made to the capital structure based on changes in economic conditions and planned requirements. Enterra has the ability to adjust its capital structure by issuing new equity or debt, selling assets to reduce debt or balance equity, controlling the amount it returns to unitholders, and making adjustments to its capital expenditures program.

Enterra monitors capital using an interest coverage ratio that has been externally imposed as part of the credit agreement. Enterra is required to maintain an interest coverage ratio greater than 3.00 to 1.00; this ratio is calculated as follows:

(in thousands of Canadian dollars except for ratios)	December 31, 2008	December 31, 2007
Interest coverage (1):		
Cash flow over the prior four quarters	116,911	94,015
Interest expenses over the prior four quarters	18,088	21,732
	6.46 : 1.00	4.33 : 1.00

(1) Note these amounts are defined terms within the credit agreements

As at December 31, 2008 and December 31, 2007, Enterra complied with the terms of the credit facilities. There have been no changes to Enterra's capital structure, objectives, policies and processes since December 31, 2007 other than the changes to its credit facilities as described in note 6.

17. Commitments

During 2008 total rental expense was $1.1 million (2007 – $1.2 million and 2006 – $0.8 million). Enterra has commitments for the following payments over the next five years:

(in thousands of Canadian dollars)	2009	2010	2011	2012	2013	There-after
Office leases (1)	1,506	1,597	2,130	635	290	-
Vehicle and other operating leases	373	117	-	-	-	-
	1,879	1,714	2,130	635	290	-

(1) Future office lease commitments may be reduced by sublease recoveries totaling $1.6 million.

18. Contingencies

Certain claims have been brought against Enterra in the ordinary course of business. In the opinion of management, all such claims are adequately covered by insurance, or if not so covered, are not expected to materially affect its financial position.

19. Segmented information

The Trust has one operating segment that is divided amongst two geographical areas. The following is selected financial information from the two geographic areas.

(in thousands of Canadian dollars)	2008	2007	2006
Revenue			
Canada	170,534	128,406	156,859
U.S.	104,963	78,630	87,549
	275,497	207,036	244,408
Property, plant and equipment			
Canada	232,335	315,569	333,911
U.S.	259,319	241,209	325,357
	491,654	556,778	659,268
Goodwill			
Canada	-	-	76,256
U.S.	-	-	-
	-	-	76,256

20. Related party transactions

On November 23, 2007, Enterra entered into a consulting agreement with Trigger Projects Ltd. for management services that would effectively be expected of the most senior manager of the Trust. This relationship was entered into to provide temporary executive management services after the former Chief Executive Officer resigned. This contract had terms that required payment for services of $40,000 per month and a bonus of up to $0.5 million on termination. The contract expired on May 31, 2008 and was extended to June 26, 2008. During 2008, total payments of $0.8 million were made to Trigger Projects Ltd. and no balance was outstanding at December 31, 2008.

In 2006 Enterra entered into a farm-out agreement with Petroflow Energy Ltd. ("JV Partner"), a public oil and gas company, to fund the drilling and completion costs of the undeveloped lands in Oklahoma. Per the agreement, JV Partner pays 100% of the drilling and completion costs to earn 70% of Enterra's interest in the well and Enterra is required to pay 100% of the infrastructure costs to support these wells, such as pipelines and salt water disposal wells. The infrastructure costs paid by Enterra are recoverable from JV Partner over three years with interest charged at a rate of 12% per annum. Infrastructure costs paid by Enterra are accounted for as a capital lease, therefore, the capital costs incurred are not included in property, plant and equipment but are current and long-term receivables. The interest income on the long-term receivables is recorded as a reduction in interest expense. The former Chief Executive Officer and former director of Enterra owned, directly and indirectly, approximately 16% of the outstanding shares of JV Partner during his tenure at Enterra. A current director of Enterra owns approximately 2% of the outstanding shares of JV Partner. As at December 31, 2008, a total of $27.9 million, split between $8.6 million of trade receivables and $19.3 million of long-term receivables, relate to infrastructure costs incurred by Enterra on behalf of JV Partner that are due from JV Partner. The receivables are for infrastructure costs incurred that are to be repaid by JV Partner over a three-year period and is subject to interest of 12% per annum. For the year ended December 31, 2008, $1.7 million of interest income was earned on the long-term receivables from JV Partner (2007 – $0.4 million). In 2008, $5.0 million of principal payments have been received (2007 - $1.1 million).

In 2007, Enterra paid Macon Resources Ltd. (“Macon”) $0.7 million, a company 100% owned by the former Chief Executive Officer, for management services provided by the former Chief Executive Officer. Macon did not provide any services to Enterra during 2008 and therefore there were no payments made in 2008. During Q1 2007, 50,000 restricted units (valued at $0.4 million based on the unit price of trust units on the grant date) were granted to Macon. On February 28, 2007, these restricted units vested and were converted to 50,441 trust units. The former Chief Executive Officer resigned as an officer and director on November 27, 2007 and February 20, 2008 respectively.

Relationship with JED Oil Inc. and JMG Exploration Inc.

On January 1, 2006, Enterra terminated a Technical Services Agreement with JED Oil Inc (“JED”), which had provided for services required to manage the Trust’s field operations and governed the allocation of general and administrative expenses between the two entities. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On September 28, 2006, Enterra terminated the existing farmout, joint services and an Agreement of Business Principles with JED. Concurrent with the termination of the agreements, the Trust settled all amounts owing to JED.

In September 2006, Enterra sold $44.0 million of petroleum and natural gas properties to JED in exchange for $30.9 million of petroleum and natural gas properties and the settlement of the $13.1 million balance due to JED.

Previously, under an Agreement of Business Principles, properties acquired by the Trust were contract operated and drilled by JMG Exploration, Inc. (“JMG”), a publicly traded oil and gas exploration company, if they were exploration properties, and contract operated and drilled by JED, a publicly traded oil and gas development company, if they were development projects. Exploration of the properties was done by JMG, which paid 100% of the exploration costs to earn a 70% working interest in the properties. If JMG discovered commercially viable reserves on the exploration properties, the Trust had the right to purchase 80% of JMG’s working interest in the properties at a fair value as determined by independent engineers. Had the Trust elected to have JED develop the properties, development would have been done by JED, which would pay 100% of the development costs to earn 70% of the interests of both JMG and the Trust. The Trust had a first right to purchase assets developed by JED.

21. Differences between Canadian and United States Generally Accepted Accounting Principles

The consolidated financial statements of Enterra Energy Trust ("Enterra") have been prepared in accordance with Canadian GAAP (in thousands of Canadian dollars except unit and per unit information) which differs in some respects from U.S. GAAP. Differences in accounting principles as they pertain to the consolidated financial statements are immaterial except as described below.

The application of U.S. GAAP would have the following effect on net income (loss) as reported for the year ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
Net income (loss) under Canadian GAAP	$ 7,061	$ (142,036)	$ (64,239)
Adjustments for U.S. GAAP			
Depletion expense (a)	(60,560)	59,731	(357,312)
Related income taxes	14,885	(17,917)	135,822
Gain on commodity contracts (b)	-	-	1,289
Related income taxes	-	-	(441)
Reverse unit based compensation expense under Canadian GAAP (f)	4,415	4,128	3,229
Unit-based compensation recovery (expense) under U.S. GAAP (f)	(160)	1,230	(935)
Non-controlling interest (e)	-	-	(36)
Interest accretion on convertible debentures under Canadian GAAP (h)	1,728	1,339	35
Amortization of other assets (h)	(1,242)	(848)	-
Gain on warrants (c)	-	-	1,215
Foreign exchange (g)	2,071	2,078	848
Adjustment to goodwill impairment due to EIC-151 (e)	-	26,631	-
Net loss under U.S. GAAP before cumulative effect of change in accounting policy under SFAS 123R	$ (31,802)	$ (65,664)	$ (280,525)
Cumulative effect of change in accounting policy under SFAS 123R (f)	-	-	177
Net loss under U.S. GAAP	$ (31,802)	$ (65,664)	$ (280,348)
Other comprehensive loss:			
Cumulative translation adjustment (g)	34,869	(23,558)	(1,082)
Other comprehensive income (loss) under U.S. GAAP	$ 3,067	$ (89,222)	$ (281,430)
Net loss under U.S. GAAP	$ (31,802)	$ (65,664)	$ (280,348)
Deficit, beginning of year, under U.S. GAAP	(25,928)	(352,054)	(422,991)
Distributions declared (Canadian and U.S. GAAP)	-	(31,576)	(90,698)
Temporary equity adjustment (d)	33,259	423,366	441,983
Deficit, end of year, under U.S. GAAP	$ (24,471)	$ (25,928)	$ (352,054)
Weighted average units for U.S. GAAP (000's)			
Basic and diluted	61,661	59,767	44,846
Net loss per unit under U.S. GAAP before cumulative effect of change in accounting policy under SFAS 123R:			
Basic and diluted	$ (0.52)	$ (1.10)	$ (6.26)

Net loss per unit under U.S. GAAP						
Basic and diluted	$	(0.52)	$	(1.10)	$	(6.25)

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported at December 31, 2008 and 2007:

	2008		2007	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets:				
Current assets	$ 76,054	$ 76,054	$ 39,009	$ 39,009
Property, plant and equipment (a)	491,654	68,010	556,778	241,665
Long-term receivables	19,310	19,310	4,003	4,003
Other assets (h)	-	3,944	-	5,186
Future/deferred income tax (a)	-	112,071	-	97,182
	$ 587,018	$ 279,389	$ 599,790	$ 387,045
Liabilities:				
Current liabilities (f)	$ 137,602	$ 133,912	$ 214,191	$ 214,528
Convertible debentures (h)	113,420	120,331	111,692	120,331
Asset retirement obligations	22,151	22,151	29,939	29,939
Future/deferred income tax (a)	19,429	-	24,784	-
	292,602	276,394	380,606	364,798
Mezzanine equity (d)	-	37,295	-	70,651
Unitholder's Equity				
Unitholders' capital (d)	669,667	-	667,690	-
Equity component of convertible debentures (h)	3,977	-	3,977	-
Warrants (c)	-	-	1,215	-
Contributed surplus (f)	8,620	-	4,660	-
Accumulated other comprehensive income (loss) (g)	18,471	(9,829)	(44,978)	(22,476)
Deficit (d)	(406,319)	(24,471)	(413,380)	(25,928)
	294,416	(34,300)	219,184	(48,404)
	$ 587,018	$ 279,389	$ 599,790	$ 387,045

(a) Property, plant and equipment

Under Canadian GAAP, the impairment test limits the capitalized costs of oil and natural gas assets to the discounted estimated future net revenue from proved and probable oil and natural gas reserves using forecast prices plus the costs of unproved properties less impairment. The discount rate used is a risk free interest rate.

Under U.S. GAAP, the full cost method of accounting for oil and natural gas activities requires Enterra to perform an impairment test using after-tax future net revenue from proved oil and natural gas reserves, discounted at 10% plus the cost of unproved properties less impairment. The prices and costs used in the U.S. GAAP ceiling test are those in effect at the consolidated balance sheet date. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ.

There were ceiling test impairments recognized under U.S. GAAP at December 31, 2008, 2007, 2006, 2005, 2004 and 2001. At December 31, 2008, Enterra recognized a U.S. GAAP ceiling test write-down of $113.1 million ($81.0 million after tax) in its Canadian cost center. No ceiling test impairment was recorded at December 31, 2008 in the U.S. cost center. At December 31, 2007, Enterra recognized a U.S. GAAP ceiling test write-down of $1.0 million ($0.7 million after tax) in its Canadian cost center and no ceiling test impairment was recognized in the U.S. cost center. At December 31, 2006, Enterra recognized an additional ceiling test write-down under U.S. GAAP of $76.9 million ($53.8 million after tax) in its Canadian cost center and $292.0 million ($175.2 million after tax) in its U.S. cost center. Prior to 2006, Enterra recognized ceiling test write-downs under U.S. GAAP of $72.8 million ($46.3 million after tax) in its Canadian cost center and $3.0 million ($2.0 million after tax) in its U.S. cost center.

Under Canadian GAAP, pursuant to EIC-151, property, plant and equipment increased as a result of the conversion of one class of exchangeable shares into trust units. Under U.S. GAAP, all classes of exchangeable shares are classified as mezzanine equity, valued at their redemption value. Conversion of exchangeable shares does not result in an increase in property, plant and equipment. This GAAP difference in the valuation of property, plant and equipment results in an increase in depletion expense during the periods presented for Canadian GAAP as compared with U.S. GAAP.

These differences in the carrying value of property, plant and equipment results in depletion expense being different under U.S. GAAP as compared with Canadian GAAP. For the years ended December 31, 2008, 2007 and 2006, depletion expense under U.S. GAAP was lower by $52.5 million ($35.3 million net of tax), $60.7 million ($42.5 million net of tax) and $12.6 million ($8.3 million net of tax), respectively.

(b) Commodity contracts and marketing contracts

Prior to January 1, 2007, under Canadian GAAP, Enterra's physical delivery contracts were not considered commodity contracts and were not measured at fair value on the consolidated balance sheet. Beginning January 1, 2007, Enterra records physical delivery contracts at fair value on the balance sheet at each reporting date, consistent with the accounting required under U.S. GAAP.

(c) Warrants

Enterra accounted for purchase warrants as equity under Canadian GAAP. Under US GAAP the share purchase warrants were accounted for as liabilities with changes in fair value recorded in the statement of operations. In April of 2008 the warrants expired and at December 31, 2007, the estimated fair value of the warrants were nil.

(d) Unitholder's mezzanine equity

Under Canadian GAAP, the trust units are considered to be permanent equity and are classified as unitholders' capital. A U.S. GAAP difference exists due to the redemption feature attached to each trust unit. Trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of $100,000 per year or a greater limit at the discretion of Enterra. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of Enterra and second by issuance of promissory notes by Enterra.

The redemption feature causes the trust units to be classified as mezzanine equity under U.S. GAAP. Mezzanine equity is valued at an amount equal to the redemption value of the trust units at the balance sheet date. Included in the redemption value of the trust units is the redemption value of the exchangeable shares, if any, as if all exchangeable shares had previously been converted into trust units. Any increase or decrease in the redemption value during a period is charged to the deficit.

As at December 31, 2008, unitholders' capital was reduced by $669.7 million (December 31, 2007 - $ 667.7 million) and the redemption value of the trust units of $37.3 million (December 31, 2007 - $70.7 million) was recorded as mezzanine equity. The change in the redemption value of the trust units is recorded as a reduction or increase to the deficit. For the year ended December 31, 2008, the deficit was reduced by $33.3 million (December 31, 2007 – $423.4 million and December 31, 2006 – $442.0 million).

(e) Exchangeable securities issued by subsidiaries of income trusts pursuant to EIC-151

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" which 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 non-transferable shares be classified as equity. Enterra's exchangeable shares are transferable and, in accordance with EIC-151, have been classified as non-controlling interest on the Canadian GAAP consolidated balance sheets.

Since a portion of Enterra's exchangeable shares were not initially recorded at fair value, subsequent exchanges for trust units are measured at the fair value of the trust units issued. The excess of fair values over book values on the exchange are recorded as additions to property, plant and equipment and goodwill. In addition, non-controlling interest is reflected as a reduction of such earnings in the Enterra's consolidated statements of loss and comprehensive loss.

During 2008, Enterra did not have any exchangeable shares outstanding; therefore, there was no impact from EIC-151 during the year. The cumulative effect from prior years of EIC-151 as of December 31, 2008 increased property, plant and equipment by $1.8 million (December 31, 2007 - $1.8 million), increased goodwill by $26.6 million (December 31, 2007 - $26.6 million), increased future income tax liability by $0.7 million (December 31, 2007 - $0.7 million), increased unitholder's capital by $28.3 million (December 31, 2006 - $28.3 million), and increased the deficit by $0.4 million (December 31, 2007 - $0.4 million). Under US GAAP, these adjustments are reversed as the exchangeable shares are included in temporary equity.

(f) Unit-based compensation

Effective January 1, 2006, Enterra adopted SFAS No. 123 (revised 2004), "Share-Based Payment", ("SFAS 123R") which is a revision of SFAS No. 123, "Accounting for Stock-based Compensation". SFAS 123R requires all unit-based payments to employees, including grants of employee unit options, be recognized in the financial statements based on their fair values. Liability classified awards, such as Enterra's restricted units, performance units and unit options are remeasured to fair value at each consolidated balance sheet date until the award is settled rather than being treated as an equity classified award on the grant date as required under Canadian GAAP. Enterra has adopted this standard by applying the modified prospective method. As a result of the adoption of SFAS 123R, in the year ended December 31, 2006, Enterra has increased current liabilities by $0.6 million, which represented the fair value of all outstanding unit options at January 1, 2006, in proportion to the requisite service period rendered to that date. In addition, contributed surplus was reduced by $0.5 million and net earnings have been increased by $0.2 million representing previously recognized compensation cost for all outstanding unit options and a credit to record the cumulative effect of a change in accounting principle. Changes in fair value between periods are charged or credited to earnings with a corresponding change in current liabilities. As at December 31, 2008, the fair value increase recognized within current liabilities was $0.2 million (December 31, 2007 – decrease of $1.2 million and December 31, 2006 – increase of $0.9 million).

The number of Enterra trust units reserved for issuance for the Trust's outstanding options, restricted units and performance units shall not exceed 10% of the aggregate number of issued and outstanding trust units of Enterra. Enterra issues units out of treasury upon the exercise of all unit options, restricted units and performance units.

For the years ended December 31, 2008 and 2007, Enterra recorded the following unit-based compensation (000s):

	Restricted and performance units			Unit options			Total		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Unit-based compensation (recovery) expense	$145	$(1,012)	$1,280	$ 15	$(218)	($345)	$ 160	($1,230)	$935

A summary of the status of the unvested options, restricted units and performance units as of December 31, 2008, and changes during the years then ended, is presented below:

	Number of unvested options	Weighted average grant date fair value	Number of unvested restricted units	Weighted average grant date fair value	Number of unvested performance units	Weighted average grant date fair value
Unvested, December 31, 2007	764,001	$ 1.04	1,057,482	$ 4.77	454,171	$ 6.29
Granted	210,000	0.70	2,070,683	3.77	-	-
Vested	(387,333)	0.98	(718,111)	3.99	-	-
Forfeited	(230,004)	1.05	(130,269)	4.37	(279,773)	7.61
Unvested, December 31, 2008	356,664	$ 0.90	2,279,786	$ 4.13	174,398	$ 4.17

The following tables provide information related to unit option, restricted unit and performance unit activity during the years ended December 31, 2008:

	Number of unit options	Weighted average exercise price	Weighted average contract life	Aggregate intrinsic value (000's)
Options outstanding, January 1, 2008	1,474,334	$ 14.51		
Options granted	210,000	2.81		
Options forfeited	(642,334)	21.65		
Options outstanding, December 31, 2008	1,042,000	$ 7.75	2.65	$ -
Options expected to vest, December 31, 2008	685,336	$ 8.45	2.59	$ -
Options exercisable, December 31, 2008	685,336	$ 8.45	2.59	$ -

	Number of units	Weighted average contract life	Aggregate intrinsic value (000's)
Restricted units outstanding, January 1, 2008	1,057,483		
Restricted units granted	2,070,683		
Restricted units exercised	(718,111)		
Restricted units forfeited	(130,269)		
Restricted units outstanding, December 31, 2008	2,279,786	1.63	$ 1,368
Restricted units expected to vest, December 31, 2008	1,915,020	1.63	$ 1,149
Restricted units exercisable, December 31, 2008	-	-	$ -

	Number of units	Weighted average contract life	Aggregate intrinsic value (000's)
Performance units outstanding, January 1, 2008	454,171		
Performance units granted	-		
Performance units exercised	-		
Performance units forfeited	(279,773)		
Performance units outstanding, December 31, 2008	174,398	0.77	$ -
Performance units expected to vest, December 31, 2008	146,494	0.77	$ -
Performance units exercisable, December 31, 2008	-	-	$ -

The intrinsic value of a unit option is the amount by which the current market value of the underlying unit exceeds the exercise price of the option. The intrinsic value of a restricted unit is the current market value of the underlying unit. The intrinsic value of a performance unit is the market value of the underlying unit multiplied by the performance factor at year end which was estimated to be nil in 2008, 2007 and 2006.

The fair value of each stock option award is estimated using the Black-Scholes option pricing model based on assumptions noted in the following table.

	2008	2007	2006
Risk-free interest rate (%)	1.25	4.5	4.5
Expected term (years)	1.1 – 3.1	2.1 – 3.9	2.0 – 4.6
Expected cash distribution yield (%)	-	-	14
Expected volatility (%)	130 – 159	63 – 66	41 – 69

The intrinsic value of options exercised in 2008 was nil (2007 – nil and 2006 – $0.1 million). The weighted average grant date fair value for options granted in 2008 was $0.70 (2007 - $1.02 and 2006 – $1.03).

The fair value of each restricted unit was based on Enterra's weighted average unit price around the date of grant and each subsequent reporting period until the date of settlement.

The intrinsic value of restricted units exercised in 2008 was $1.4 million (2007 - $1.2 million and 2006 - $0.4 million). The weighted average grant date fair value of the restricted units granted was $3.77 (2007 – $3.53 and 2006 – $14.90).

The fair value of each performance unit was based on Enterra's weighted average unit price around the date of grant and each subsequent reporting period until the date of settlement adjusted for the estimated payout multiple.

The intrinsic value of performance units exercised in 2008 was nil (2007 and 2006 – nil) since there were no performance units vested. There were no performance units granted during 2008, therefore, the weighted average grant date fair value of the performance units granted was nil (2007 – $3.20 and 2006 – $15.06).

As of December 31, 2008, there was $0.1 million (2007 – $0.1 million and 2006 – $0.5 million) of total unrecognized compensation cost related to unvested unit options. The cost is expected to be recognized over a weighted average period of 0.7 years (2007 – 1.2 years and 2006 – 1.9 years).

As of December 31, 2008, there was $1.0 million (2007 - $0.9 million and 2006 - $2.7 million) of unrecognized compensation cost related to unvested restricted units. The cost is expected to be recognized over a weighted average period of 1.6 years (2007 – 1.2 years and 2006 – 2.0 years).

As of December 31, 2008, 2007 and 2006, there was no amount of unrecognized compensation cost related to unvested performance units.

Under U.S. GAAP, the amount of compensation costs related to options, restricted units and performance units to be capitalized was insignificant.

(g) Cumulative translation adjustment and other comprehensive income

Enterra's U.S. oil and natural gas properties are considered to be self sustaining. Under Canadian GAAP, a portion of the cumulative translation adjustment is recognized in income as the investment in the foreign operations is reduced. Under U.S. GAAP, the cumulative translation adjustment is only recognized in income upon disposition of the segment. For the year ended December 31, 2008, $2.1 million (2007 - $2.1 million and 2006 - $0.8 million) of the cumulative translation adjustment was recognized as a foreign exchange loss under Canadian GAAP. The difference in other comprehensive income under U.S. GAAP as compared to Canadian GAAP is a result of differences between the carrying values of the assets and liabilities of the U.S. self sustaining operations under U.S. GAAP versus Canadian GAAP. These differences in the carrying values result in differences in the foreign exchange gains and losses on translation of the U.S. operations.

(h) Convertible debentures

In November 2006 and April 2007, Enterra issued convertible debentures. Under Canadian GAAP, Enterra's convertible debentures are classified as debt with a portion representing the value associated with the conversion feature being allocated to equity and the issue costs netted against the debt. Under U.S. GAAP, the convertible debentures in their entirety are classified as debt and the issue costs classified as other assets. In addition, under Canadian GAAP, a non-cash interest expense representing the effective yield of the debt component is recorded in the consolidated statements of loss and comprehensive loss with a corresponding credit to the convertible debenture liability balance to accrete that balance to the full principal due on maturity. Under U.S. GAAP, this non-cash interest expense is not recorded but the issue costs are amortized over the life of debentures.

(i) Additional disclosure under U.S. GAAP

	2008	2007
Components of accounts receivable:		
Trade	$ 40,581	$ 11,497
Accruals	15,156	19,983
Allowance for doubtful accounts	(9,618)	(1,089)
	$ 46,119	$ 30,391
Components of prepaid expenses:		
Prepaid expenses	$ 992	$ 1,290
Funds on deposit	967	980
	$ 1,959	$ 2,270
Components of accounts payable:		

Accounts payable	$ 18,741	$ 22,316
Accrued liabilities	19,208	13,447
	$ 37,949	$ 35,763

(j) Select pro forma financial information for the acquisition of Trigger Resources (unaudited)

On April 30, 2007, Enterra acquired Trigger Resources Ltd. Under U.S. GAAP, select pro forma financial information is disclosed under FAS 141.54 as if the acquisition had occurred on January 1, 2007 and January 1, 2006 respectively instead of the actual closing of April 30, 2007. The following table shows select pro forma financial information:

		2007 (unaudited)		2006 (unaudited)
Oil and natural gas revenue	$	217,994	$	272,239
Net loss		(67,681)		(288,116)
Per unit – basic and diluted	$	(1.10)	$	(5.87)

(k) Uncertainty in tax positions

On January 1, 2007, Enterra adopted the provisions of FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (“FIN 48”), an interpretation of FASB Statement No. 109, “Accounting for Income Taxes.” FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation requires that Enterra recognize the impact of a tax position in the financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, and accounting in interim periods and disclosure. In accordance with the provisions of FIN 48, any cumulative effect resulting from the change in accounting principle is to be recorded as an adjustment to the opening deficit balance.

As at December 31, 2008 and 2007, Enterra did not have any amounts recorded pertaining to uncertain tax positions. The adoption of FIN 48 did not impact Enterra’s tax provision.

Enterra files federal and provincial income tax returns in Canada and federal, state and local income tax returns in the U.S., as applicable. Enterra may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the date of mailing of the original notice of assessment in respect of any particular taxation year. For the Canadian tax returns, the open taxation years range from 2004 to 2008. For the U.S. tax returns, the open taxation years range from 2006 to 2008. The U.S. federal statute of limitations for assessment of income tax is generally closed for the tax years ending on or prior to 2002. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. Tax authorities of Canada and U.S. have not audited any of Enterra’s, or its subsidiaries’, income tax returns for the open taxation years noted above.

Enterra recognizes interest and penalties related to uncertain tax positions in tax expense. During the years ended December 31, 2008, 2007 and 2006, there were no charges for interest or penalties.

(l) Fair value of commodity contracts

Certain of Enterra’s assets and liabilities are reported at fair value in the balance sheets. The following tables provide fair value measurement information for such assets and liabilities as of December 31, 2008 and December 31, 2007 including items where the fair value is disclosed on a reoccurring basis.

The carrying values of cash and cash equivalents, accounts receivable, bank indebtedness, accounts payable and accrued liabilities, and note payable included in the accompanying consolidated balance sheets approximated fair value at December 31, 2008 and December 31, 2007 as the amounts were short term in nature or bore interest at floating rates. These assets and liabilities are not presented in the following tables.

	As at December 31, 2008				
			Fair Value Measurements Using:		
	Carrying Amount	Fair Value	Level 1	Level 2	Level 3
Commodity contracts	14,338	14,338	-	14,338	-
Convertible debentures	(113,420)	(76,049)	(76,049)	-	-

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs have lower priorities. The Trust uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. When available, Enterra measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements
Convertible debentures – The fair values of the convertible debentures are estimated using unadjusted quoted prices in active markets.

Level 2 Fair Value Measurements
Commodity contracts – The fair values of the commodity contracts are estimated using discounted cash flow calculations based upon forward commodity price curves and quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the contracts taking into consideration the credit worthiness of those brokers or counterparties.

Level 3 Fair Value Measurements
The Trust does not have any financial assets or financial liabilities whose fair value is measured using this method.

(k) New accounting pronouncements not yet adopted

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require an entity to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling are effective for disclosures in the Trust’s Annual Report for the year ended December 31, 2009. Early adoption is not permitted. The Trust is currently assessing the impact that the adoption will have on its disclosures, operating results, financial position and cash flows.

In May 2008, FASB issued FASB Staff Position No. APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)”. An issuer of a convertible debt instrument within the scope of the staff position is required to separate the instrument into a liability-classified component and an equity-classified component. The staff position is effective for the fiscal year beginning after

December 15, 2008. Enterra is currently assessing the impact of the staff position and expects that the guidance will bring U.S. GAAP in line with Canadian GAAP.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities". SFAS 161 requires entities with derivative instruments to disclose information that should enable financial statement users to understand how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133, how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of this statement is not expected to have a material effect on the Trust's disclosures within the consolidated financial statements.

In December 2007, FASB issued SFAS No. 141 (revised 2007) “Business Combinations” which replaces SFAS No. 141 “Business Combinations”. The new standard requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; and recognize and measure the goodwill acquired in the business combinations for which the acquisition date is on or after January 1, 2009. The adoption of this accounting standard will impact business combinations, if any, after the adoption date.

In December 2007, FASB issued SFAS No. 160 “Non-controlling Interests in Consolidated Financial Statements” (“SFAS 160”) which requires the Trust to report non-controlling interests in subsidiaries as equity in the consolidated financial statements; and all transactions between an entity and non controlling interests as equity transactions. SFAS 160 is effective for Enterra commencing on January 1, 2009 and it will not impact the current consolidated financial statements of the Trust.

In September 2006, the FASB issued SFAS No. 157 “Fair Value Measurements”. SFAS 157 defines fair value, establishes a framework for measuring fair value under US GAAP and expands disclosures about fair value measurements. This statement was adopted by the Trust in 2008. In February 2008, the FASB issued FASB Staff Position (“FSP”) SFAS 157-2 which delayed the effective date of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. These non-financial items include assets and liabilities such as asset retirement obligations and non-financial assets acquired and liabilities assumed in a business combination. Beginning January 1, 2009, the Trust will adopt the provisions for non-financial assets and non-financial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The Trust does not expect the provisions of SFAS 157 related to these items to have a material impact on the consolidated financial statements.

In May 2009, the FASB issued SFAS No. 165, “Subsequent Events”. SFAS No. 165 is intended to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this Statement sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. This Statement is effective for interim and annual periods ending after June 15, 2009. The adoption of this statement may impact the accounting or disclosure of future subsequent events, if any, after the effective date.

22. SUPPLEMENT INFORMATION – OIL AND GAS PRODUCING ACTIVITIES (unaudited)

The following disclosures have been prepared in accordance with SFAS No. 69 – “Disclosures about Oil and Gas Producing Activities”. Amounts are in Canadian dollars unless otherwise denoted.

OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of “proved” and “proved developed” crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids (“NGL”) that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale that varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time that estimates were made and the Trust’s estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust’s share of future production from Canadian reserves to be materially different from that presented.

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to the Trust's oil and gas producing activities for the years ended December 31:

(thousands of dollars)	Canada	United States	2008 Total
Revenue	136,946	80,201	217,147
Deduct:			
Production costs	38,937	19,401	58,338
Depletion, depreciation and amortization	155,762	4,175	159,937
Results of operations from producing activities	(57,753)	56,625	(1,128)

(thousands of dollars)	Canada	United States	2007 Total
Revenue	99,492	62,179	161,671
Deduct:			
Production costs	45,600	19,223	64,823
Depletion, depreciation and amortization	85,015	5,955	90,970
Results of operations from producing activities	(31,123)	37,001	5,878

(thousands of dollars)	Canada	United States	2006 Total
Revenue	128,607	67,514	196,121
Deduct:			
Production costs	35,513	14,848	50,361
Depletion, depreciation and amortization	207,079	351,681	558,760
Results of operations from producing activities	(113,985)	(299,015)	(413,000)

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred by the Trust in oil and gas producing activities for the years ended December 31 are as follows:

(thousands of dollars)	Canada	United States	2008 Total
Property acquisition costs:			
Proved	-	-	-
Unproved	3,049	10,805	13,854
Exploration costs	-	-	-
Development costs	18,399	861	19,260
Property acquisition, exploration, and development expenditures	21,448	11,666	33,114

(thousands of dollars)	Canada	United States	2007 Total
Property acquisition costs:			
Proved	81,382	-	81,382
Unproved	-	5,300	5,300
Exploration costs	-	-	-
Development costs	17,759	10,839	28,598
Property acquisition, exploration, and development expenditures	99,141	16,139	115,280

(thousands of dollars)	Canada	United States	2006 Total
Property acquisition costs:			
Proved	25,621	332,290	357,911
Unproved	6,736	26,384	33,120
Exploration costs	-	-	-
Development costs	20,868	8,031	28,899
Property acquisition, exploration, and development expenditures	53,225	366,705	419,930

Acquisition costs include costs incurred to purchase, lease or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas as well as additions to asset retirement obligations.

Enterra capitalizes a portion of general and administrative costs associated with exploration activities and development activities. Transaction costs directly attributable to successful acquisitions are also capitalized.

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to the Trust's oil and gas exploration, development and producing activities for the years ended December 31 consist of:

(thousands of dollars)	Canada	United States	2008 Total
Oil and gas properties	716,814	391,178	1,107,992
Less:			
Accumulated depletion, depreciation and amortization	(680,733)	(359,249)	(1,039,982)
Net capitalized costs	36,081	31,929	68,010

(thousands of dollars)	Canada	United States	2008 Total
Unproven oil and gas properties	11,779	11,854	23,633
Proven oil and gas properties	24,302	20,075	44,377
Net capitalized costs	36,081	31,929	68,010

(thousands of dollars)	Canada	United States	2007 Total
Oil and gas properties	739,172	328,945	1,068,117
Less:			
Accumulated depletion, depreciation and amortization	(526,573)	(299,879)	(826,452)
Net capitalized costs	212,599	29,066	241,665

(thousands of dollars)	Canada	United States	2007 Total
Unproven oil and gas properties	18,571	-	18,571
Proven oil and gas properties	194,028	29,066	223,094
Net capitalized costs	212,599	29,066	241,665

OIL AND GAS RESERVE INFORMATION

At December 31, 2008, Enterra reserves were located in Canada in the provinces of Alberta, British Columbia and Saskatchewan as well as in the United States in the state of Oklahoma. McDaniel & Associates Consultants Ltd. ("McDaniel") reviewed the reserves in Canada and Haas Petroleum Engineering Services, Inc. ("Haas") reviewed the reserves in Oklahoma. The tables below provide a summary of the Trust's proved developed and undeveloped reserves after deductions of royalties as evaluated by McDaniel and Haas based on constant price and cost assumptions.

CANADA	Crude oil and NGL (mbbl)	Natural gas (mmcf)
Net proved developed and undeveloped reserves after royalties		
End of year 2005	5,343	33,096
Revision of previous estimates	368	(1,639)
Extensions and discoveries	-	-
Purchase of reserves in place	406	2,558
Production	(1,342)	(5,474)
Sales of reserves in place	(402)	(4,874)
End of year 2006	4,373	23,667
Revision of previous estimates	149	2,250
Extensions and discoveries	92	(23)
Purchase of reserves in place	757	8,813
Production	(1,209)	(5,930)
Sales of reserves in place	(277)	(623)
End of year 2007	3,885	28,154
Revision of previous estimates	(341)	(3,449)
Extensions and discoveries	128	457
Purchase of reserves in place	3	9
Production	(914)	(4,070)
Sales of reserves in place	(767)	(6,524)
End of year 2008	1,994	14,577
Net proved developed reserves after royalties		
End of year 2006	4,253	22,003
End of year 2007	3,637	26,399
End of year 2008	1,994	14,577

UNITED STATES	Crude oil and NGL (mbbl)	Natural gas (mmcf)
Net proved developed and undeveloped reserves after royalties		
End of year 2005	-	1,601
Revision of previous estimates	(698)	(12,409)
Extensions and discoveries	2	2,560
Purchase of reserves in place	2,232	54,332
Production	(179)	(7,287)
Sales of reserves in place	-	-
End of year 2006	1,357	38,797

Revision of previous estimates	(334)	9,479
Extensions and discoveries	59	3,293
Purchase of reserves in place	-	-
Production	(185)	(7,722)
Sales of reserves in place	-	-
End of year 2007	897	43,847
Revision of previous estimates	2,911	(11,150)
Extensions and discoveries	278	2,399
Purchase of reserves in place	-	-
Production	(159)	(7,194)
Sales of reserves in place	-	(951)
End of year 2008	3,927	26,951
Net proved developed reserves after royalties		
End of year 2006	1,104	31,637
End of year 2007	797	37,454
End of year 2008	3,649	23,105

Notes:

1. Net after royalty reserves are the Trust's overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.
2. Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.
3. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
4. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information has been developed utilizing procedures described by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of the Trust. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Trust or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of Enterra's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2008 was based on the following benchmark prices: Edmonton light crude price of $45.12/bbl, Alberta average plant gate price of $6.15/mcf, WTI oil price of US$44.60/bbl and US Henry Hub gas prices of US$5.71/mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2007 was based on the following benchmark prices: Edmonton light crude price of $93.76/bbl, Alberta average plant gate price of $6.32/mcf, WTI oil price of US$95.48/bbl and US Henry Hub gas prices of US$7.83/mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2006 was based on the following benchmark prices: Edmonton light crude price of $67.06/bbl, Alberta average plant gate price of $5.93/mcf, and US Henry Hub gas prices of US$5.63/mcf.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Trust's crude oil and natural gas reserves at December 31 for the years presented.

(million of dollars)	Canada	United States	2008 Total
Future cash inflows	210	369	579
Future costs:			
Future production and development costs	(160)	(181)	(341)
Future income taxes	-	(32)	(32)
Future net cash flows	50	156	206
Deduct: 10% annual discount factor	(9)	(45)	(54)
Standardized measure of discounted future net cash flows	41	111	152

(millions of dollars)	Canada	United States	2007 Total
Future cash inflows	431	389	820
Future costs:			
Future production and development costs	(212)	(153)	(365)
Future income taxes	(18)	(15)	(33)
Future net cash flows	201	221	422
Deduct: 10% annual discount factor	(43)	(72)	(115)
Standardized measure of discounted future net cash flows	158	149	307

(millions of dollars)	Canada	United States	2006 Total
Future cash inflows	390	297	687
Future costs:			
Future production and development costs	(185)	(107)	(292)
Future income taxes	(10)	(7)	(17)
Future net cash flows	195	183	378
Deduct: 10% annual discount factor	(43)	(52)	(95)
Standardized measure of discounted future net cash flows	152	131	283

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31 for the years presented:

(thousands of dollars)	Canada	United States	2008 Total
Future discounted net cash flows at beginning of year	158,353	149,495	307,848
Revenues, net of royalties and production costs	(18,939)	(32,880)	(51,819)
Change due to prices, net of production costs	(111,783)	(98,040)	(209,823)
Development costs during the year	11,121	19,143	30,264
Changes in estimated future development costs	(1,000)	(20,022)	(21,022)
Changes due to extensions, discoveries and improved recovery	2,428	17,609	20,037
Change due to revisions	(10,893)	27,346	16,453
Acquisitions of reserves	54	-	54
Disposition of reserves	(22,055)	(4,117)	(26,172)
Accretion of discount	15,835	14,950	30,785
Other significant factors	-	32,587	32,587
Changes in income taxes	17,879	5,212	23,091
Future discounted net cash flows at end of year	41,000	111,283	152,283

(thousands of dollars)	Canada	United States	2007 Total
Future discounted net cash flows at beginning of year	152,330	131,313	283,643
Revenues, net of royalties and production costs	(55,309)	(35,187)	(90,496)
Change due to prices, net of production costs	60,702	33,099	93,801
Development costs during the year	16,060	15,730	31,790
Changes in estimated future development costs	(20,143)	(12,282)	(32,425)
Changes due to extensions, discoveries and improved recovery	6,802	12,942	19,744
Change due to revisions	(32,518)	16,330	(16,188)
Acquisitions of reserves	31,769	-	31,769
Disposition of reserves	(8,469)	-	(8,469)
Accretion of discount	15,233	13,131	28,364
Other significant factors	-	(17,071)	(17,071)
Changes in income taxes	(8,104)	(8,510)	(16,614)
Future discounted net cash flows at end of year	158,353	149,495	307,848

(thousands of dollars)	Canada	United States	2006 Total
Future discounted net cash flows at beginning of year	283,965	2,812	286,777
Revenues, net of royalties and production costs	(88,488)	(46,702)	(135,190)
Change due to prices, net of production costs	(71,845)	(1,000)	(72,845)
Development costs during the year	17,883	7,735	25,618
Changes in estimated future development costs	(17,906)	(11,183)	(29,089)
Changes due to extensions, discoveries and improved recovery	-	9,695	9,695
Change due to revisions	(47,326)	47,615	289

Acquisitions of reserves	25,405	130,291	155,696
Disposition of reserves	(25,672)	-	(25,672)
Accretion of discount	28,397	281	28,678
Other significant factors	-	-	-
Changes in income taxes	47,917	(8,231)	39,686
Future discounted net cash flows at end of year	152,330	131,313	283,643

Note:

1. The schedules above are calculated using year-end prices, costs, statutory tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

ITEM 19 – EXHIBITS

1. By-laws of Enterra Energy Trust, incorporated by reference.

2. Voting Trust agreement, incorporated by reference.

3. Material Contracts, incorporated by reference.

8. List of Subsidiaries

11. Code of Conduct

12.1 Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act.

12.2 Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act.

13.1 Certification furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act (such certificate is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporate by reference with any filings under the Securities Act).

13.2 Certification furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act (such certificate is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporate by reference with any filings under the Securities Act).

SIGNATURES

The registrants certifies that it meets all of the requirements for filing on Form 20-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: June 22, 2009

Enterra Energy Trust
'signed' Blaine Boerchers
Senior V.P. Finance and CFO