ENTERRA ENERGY TRUST
Form 40-F
March 31, 2006

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

FORM 40-F

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

x Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended **December 31, 2005**

Commission File Number **000-32115**

ENTERRA ENERGY TRUST
(Exact name of registrant as specified in its charter)

Alberta	**1311**	**Not Applicable**
(Province or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code)	(I.R.S. Employer Identification No.)

Suite 2600, 500 - 4th Avenue S.W.
Calgary, Alberta
Canada, T2P 2V6
(403) 263-0262
(Address and telephone number of registrant's principal executive offices)

DL Services, Inc.
1420 Fifth Avenue, Suite 3400
Seattle, Washington 98101
(206) 903-8800
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

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, no par value	**Toronto Stock Exchange** **New York Stock Exchange**

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

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

For annual reports, indicate by check mark the information filed with this form:

x Annual Information Form   x Audited Annual Financial Statements

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, 2005:**

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the “Exchange Act”). If “Yes” is marked, indicate the filing number assigned to the Registrant in connection with such Rule. o Yes   x No

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for 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. x Yes   o No

Explanatory Note: Enterra Energy Trust (the "Registrant") is a Canadian issuer that is permitted, under a multijurisdictional disclosure system adopted in the United States, to prepare its Annual Report pursuant to Section 13 of the Securities Exchange Act of 1934 (the "1934 Act") in accordance with disclosure requirements in effect in Canada which differ from those of the United States. The Registrant is a "foreign private issuer" as defined in Rule 3b-4 under the 1934 Act and in Rule 405 under the Securities Act of 1933. Equity securities of the Registrant are accordingly exempt from Sections 14(a), 14(b), 14(c), 14(f) and 16 of the 1934 Act pursuant to Rule 3a12-3.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 40-F and the Exhibits included herein contain forward-looking statements concerning the Registrant's plans for drilling, exploration and development, business strategy and plans and objectives of management for future operations. Other forward-looking statements relate to the Registrant's future financial position, estimated amounts and timing of capital expenditures, royalty rates and exchange fees relate to analyses and other information that are based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "expects", "is expected", "anticipates", "plans", "projects", "estimates", "assumes", "intends" "strate "objectives", "potential" or variations thereof or stating that certain actions, events or results "may", "could", "would", "migh "will" be taken, occur or be achieved, or the negative of any of these terms and similar expressions) are not statements of historical fact and may be "forward-looking statements."

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

Forward-looking statements are subject to a variety of known and unknown risks, uncertainties and other factors that could cause actual events or results to differ from those reflected in the forward-looking statements, including, without limitation:

- The risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas;
- market demand;
- risks and uncertainties involving geology of oil and gas deposits;
- uncertainty of capital costs, operating costs, production and economic returns;
- the uncertainty of reserve estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;

- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- the Registrant’s ability to attract and retain qualified management; and
- commodity price fluctuations.

Other sections of this report may include additional factors that could adversely affect the Registrant's business and financial performance. Moreover, the Registrant operates in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, or assess the impact of all factors on the 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 Registrant's forward-looking statements are based on the beliefs, expectations and opinions of management on the date the statements are made, and the Registrant does not assume any obligation to update forward-looking statements if circumstances or management's beliefs, expectations or opinions should change. For the reasons set forth above, investors should not place undue reliance on forward-looking statements.

CURRENCY

Unless otherwise indicated, all dollar amounts in the Annual Report on Form 40-F are Canadian dollars. The exchange rate of Canadian dollars into United States dollars, based upon the noon rate of exchange as reported by the Bank of Canada, was U.S.$1.00 = CDN$1.17 on March 27, 2005 and was U.S.$1.00 = CDN$1.22 on March 27, 2006.

ANNUAL INFORMATION FORM

The Registrant's Annual Information Form for the fiscal year ended December 31, 2005 is included herein as Exhibit 1.

AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

Audited Annual Financial Statements

For audited financial statements, including the report of the auditors with respect thereto, see Exhibit 2 included herein. The Registrant's financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), which differs from United States GAAP, and is subject to Canadian auditing and auditor independence standards, and therefore may not be comparable to financial statements of United States companies. For a reconciliation of differences between Canadian and United States generally accepted accounting principles, see Note 22 - Differences Between Canadian and United States Generally Accepted Accounting Principles, of the notes to the financial statements.

Management's Discussion and Analysis

For management's discussion and analysis ("MD&A") see Exhibit 3.

Tax Matters

Purchasing, holding or disposing of securities of the Registrant may have tax consequences under the laws of the United States and Canada that are not described in this Annual Report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the period covered by this Annual Report on Form 40-F, the Registrant carried out an evaluation, under the supervision of the Registrant's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the Registrant's disclosure controls and procedures pursuant to Rules 13a-15(e) and 15d-15(e) of the 1934 Act. Based upon that evaluation, the Registrant's Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 40-F, the Registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and (ii) accumulated and communicated to the Registrant's management, including its principal executive officer and principal financial officer, to allow timely decision regarding required disclosure.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the period covered by this Annual Report on Form 40-F, no changes occurred in the Registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting.

CODE OF ETHICS FOR DIRECTORS, OFFICERS, EMPLOYEES AND CONSULTANTS

The Registrant has adopted a Code of Ethics which applies to all directors, officers, employees and consultants. It is available on the Registrant's web site at *www.enterraenergy.com* and in print to any shareholder who requests it. All amendments to the code, and all waivers of the code with respect to any of the officers covered by it, will be posted on the Registrant's web site, submitted on Form 6-K and provided in print to any shareholder who requests them.

AUDIT COMMITTEE

The Registrant's Board of Directors has a separately-designated standing Audit Committee for the purpose of overseeing the accounting and financial reporting processes of the Registrant and audits of the Registrant's annual financial statements. As of the date of the Annual Report on Form 40-F for the year ended December 31, 2005, the following individuals comprise the entire membership of the Registrant's Audit Committee, which has been established in accordance with Section 3(a)(58)(A) of the Exchange Act:

Mr. William E. Sliney
Mr. H.S. (Scobey) Hartley
Mr. Norman Wallace

Audit Committee Financial Expert

Mr. Sliney has been determined by the Registrant to meet the audit committee financial expert criteria (as defined in Item 401 of Regulation S-K under the 1934 Act) and has been designated as an audit committee financial expert for the Audit Committee. Mr. Sliney is independent as defined by the New York Stock Exchange ("NYSE") Corporate Governance Rules.

Each member of the audit committee and a majority of the board of directors is independent as defined by the NYSE Corporate Governance Rules.

CORPORATE GOVERNANCE LISTING STANDARDS

The Trust's corporate governance practices are subject to guidelines for effective corporate governance established by National Instrument 58-101 and National Policy 58-201 (collectively, the "CSA Rules"). The Trust satisfies all of the New York Stock Exchange ("NYSE") corporate governance listing standards applicable to non-U.S. companies and complies in many respects with the NYSE corporate governance listing standards applicable to U.S. companies.

With respect to the NYSE corporate governance listing standards, the Trust's corporate governance practices differ in only a number of respects from those applicable to U.S. companies. First, the NYSE listing standards require shareholder approval of all equity compensation plans and any material revisions to such plans, regardless of whether the securities to be delivered under such plans are newly issued or purchased on the open market, subject to a few limited exceptions. In contrast, the TSX rules require shareholder approval of equity compensation plans only when such plans involve newly issued securities. Equity compensation plans that do not provide for a fixed maximum number of securities to be issued must have a rolling maximum number of securities to be issued based on a fixed percentage of the issuer's outstanding securities and must also be approved by shareholders every three years. If the plan provides a procedure for its amendment, the TSX rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or an extension of the term of options held by insiders. Secondly, the NYSE listing standards require that any waivers of a company's code of business conduct and ethics for directors or executive officers be promptly disclosed. The Trust complies with the requirements of the CSA Rules which specify that material departures from the Policy on Business Conduct and Ethics by a director or executive officer which constitute a material change to the Trust will be promptly disclosed to shareholders. Third, the NYSE listing standards require that the Audit Committee charter specify that the Audit Committee assist the Board of Directors in its oversight of the Trust's compliance with legal and regulatory requirements. The Trust's Board oversees the Trust's compliance with legal and regulatory requirements. Each of the Board committees assists the Board in its oversight of the Trust's compliance with legal and regulatory requirements in each of their areas of responsibility. Fourth, the NYSE listing standards require that the corporate governance committee be comprised solely of independent directors. Keith Conrad, our Chief Executive Officer, is a member of that committee. Fifth, the NYSE listing standards require that the compensation committee be comprised solely of independent directors. Reg Greenslade, who in not considered independent, is a member of that committee. However, as of April 1, 2006, Mr. Greenslade will no longer be a member of that committee. Finally, the NYSE listing standards require that non-management directors meet at regularly scheduled executive sessions without management. Our non-management directors do not have such regularly scheduled executive sessions without management.

Disclosure of Reserves Data

As a Canadian issuer, we are required under Canadian law to comply with National Instrument 51-101 *"Standards of Disclosure for Oil and Gas Activities"* ("NI 51-101") issued by the Canadian Securities Administrators, in all of our reserves related disclosures.

In the United States however, registrants, including foreign private issuers like us, are generally required to disclose proved reserves using the standards contained in the United States Securities and Exchange Commission ("SEC") Regulation S-X. Under certain circumstances, applicable U.S. law permits us to comply with our own country's law if the requirements vary. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved and proved plus probable reserves as well as related future net revenues using forecast prices and costs. Another difference lies in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

PRINCIPAL ACCOUNTING FEES AND SERVICES - INDEPENDENT AUDITORS

The table setting forth the Registrant’s fees paid to its independent auditor, KPMG LLP for the years ended December 31, 2004 and December 31, 2005 are set forth below:

	Years ended December 31			
		2005		2004
Audit:	$	410,560	$	309,116
Audit Related:	$	316,992	$	5,000
Tax	$	40,500	$	12,500
All Other Fees		-		-
Total	$	768,052	$	326,616

“Audit Fees” are the aggregate fees billed by KPMG LLP and Deloitte & Touche LLP for the audit of the Registrant’s annual consolidated financial statements and reviews of the Registrant's interim consolidated financial statements.

“Audit-Related Fees” are fees charged by KPMG LLP in conjunction with statutory and regulatory filings such as prospectus and information circulars.

“Tax Fees” are fees for professional services rendered by KPMG LLP for reviews of tax statements regarding distributions.

Fees disclosed under the category “All Other Fees” for the 2005 and 2004 fiscal years were $0.

PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES PROVIDED BY INDEPENDENT AUDITORS

For information regarding the Audit Committee’s pre-approval procedures and policies, see “Audit Committee” in the Registrant’s Annual Information Form filed as Exhibit 1 to this Annual Report on Form 40-F.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has not entered into any off-balance sheet arrangements other than operating leases.

TABLE OF CONTRACTUAL COMMITMENTS

The following table lists as of December 31, 2005 information with respect to the Registrant’s known contractual obligations.

	Payments due by period (in 000’s)				
Contractual Obligations	***Total***	***Less than 1 year***	***1- 3 years***	***3 - 5 years***	***More than 5 years***
Short-Term Debt Obligations	$99,521	$99,521	$-	$-	$-
Interest on above debt	5,011	5,011	-	-	-
Long-Term Debt Obligations	-	-	-	-	-
Capital (Finance) Lease Obligations	2,864	1,065	1,799	--	--
Operating Lease Obligations	5,654	1,160	2,140	2,257	97
Purchase Obligations					
	24,323	-	-	-	24,323

Other Long-Term Liabilities Reflected on the Registrant's Balance Sheet under Canadian GAAP					
Total	$137,373	$106,757	$3,939	$2,257	$24,420

For additional information related to the Registrant's contractual obligations and commitments see Note 17 in the Registrant's consolidated financial statements (Exhibit 2).

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an Annual Report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

The Registrant filed an Appointment of Agent for Service of Process and Undertaking on Form F-X signed by the Registrant and its agent for service of process on November 10, 2005 with respect to the class of securities in relation to which the obligation to file the Form 40-F arises, which Form F-X is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report on Form 40-F to be signed on its behalf by the undersigned, thereunto duly authorized.

ENTERRA ENERGY CORP., AS ADMINISTRATOR OF ENTERRA ENERGY TRUST

/s/ Keith Conrad

Keith Conrad
President and Chief Executive Officer

Date: March 30, 2006

EXHIBIT INDEX

The following exhibits have been filed as part of the Annual Report on Form 40-F :

Exhibit	Description
Annual Information	
1	Annual Information Form of the Registrant for fiscal year ended December 31, 2005
2	Audited consolidated financial statements of the Registrant and notes thereto for the years ended December 31, 2005, 2004 and 2003, together with the report of the auditors thereon
3	Management's Discussion and Analysis for the year ended December 31, 2005
Certifications	
4	Certifications by the Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
5	Certifications by the Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
6	Certificate of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
7	Certificate of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
Consents	
8	Consent of KPMG LLP
9	Consent of McDaniel & Associates Consultants Ltd.
10	Consent of Sproule Associates Inc.

Enterra Energy Trust

Annual Information Form

For the year ended December 31, 2005

March 31, 2006

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Glossary

The following are defined terms used in this annual information form:

"**2nd Amended and Restated Agreement of Business Principles**" means the Amended and Restated Agreement of Business Principles among the Trust, JED and JMG, dated effective September 1, 2003 as between the Trust and JED and August 1, 2004 as among the Trust, JED and JMG;

"**Board of Directors**" means the board of directors of Enterra Energy Corp.;

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

"**EEC Exchangeable Shares**" means exchangeable shares issued by Enterra Energy, which may be exchanged 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;

"**Enterra", "we", "us", "our", or "Trust"** means Enterra Energy Trust and where the context requires includes the Trust and all of the Trust Subsidiaries as a consolidated entity;

"**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 Debt**" means the notes and any other indebtedness of the Operating Subsidiaries to the Trust from time to time;

"**Enterra Energy**" **or** " **EEC**" means Enterra Energy Corp., a corporation incorporated under the laws of Alberta and a wholly owned subsidiary of Enterra or the Trust, and administrator of the Trust pursuant to an administration agreement between the Trust and Enterra Energy dated November 25, 2003;

"**Exchangeco**" means Enterra Exchangeco Ltd., a corporation incorporated under the laws of Alberta and a wholly owned subsidiary of EECT; "**Enterra US Acqco**" means Enterra US Acquisitions Inc, a corporation organized under the laws of the state of Washington and an indirect subsidiary of the Trust;

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

"**Exchangeable Shares**" means exchangeable shares issued by Trust Subsidiaries and include where the context requires the EEC Exchangeable Shares, RMAC Exchangeable Shares and RMG Exchangeable Shares;

"**GAAP**" means generally accepted accounting and principles in Canada;

"**High Point**" means High Point Resources Inc.;

"**High Point Arrangement**" means the plan of arrangement completed on August 17, 2005 involving High Point Resources Inc. and its subsidiaries, Enterra Energy II Partner Corp., RMAC and the shareholders of High Point Resources Inc.;

"**High Point Voting and Exchange Trust Agreement**" means the voting and exchange trust agreement entered into on August 17, 2005 between the Trust, EECT, RMAC, Enterra Exchangeco Ltd. and Olympia Trust Company;

"**JED**" means JED Oil Inc., a corporation incorporated under the laws of Alberta;

"**JMG**" means JMG Exploration, Inc., a corporation incorporated under the laws of Nevada;

"**Joint Services Agreement**" means the agreement entered into between the Trust and JED, and the Trust and JMG on January 1, 2006 to replace the terminated Technical Services Agreement;

"**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 13, 2006 and effective December 31, 2005;

"**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 Enterra Energy Corp. prior to the Enterra Arrangement;

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

"**RMAC Exchangeable Shares**" means exchangeable shares issued by RMAC, which may be exchanged for Trust Units;

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

"**RMG Acquisition**" means the completion of the acquisition of Rocky Mountain Gas, Inc. (**"RMG"**) on June 1, 2005;

"**RMG Exchangeable Shares**" means exchangeable shares issued by Enterra US Acquisitions Inc., which may be exchanged for Trust Units;

"**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;

"**Sproule**" means Sproule Associates Inc., independent petroleum engineering consultants;

"**Sproule Report**" means the independent engineering evaluation by Sproule of certain oil, NGL and natural gas interests of RMG effective December 31, 2005;

"**Special Voting Right**" means the special voting right of the Trust issued by the Trust to and deposited with the Trustee, which, entities the holders of the EEC Exchangeable Shares to a number of votes at meetings of the Trust Unitholders as determined in the Voting and Exchange Trust Agreement;

"**Support Agreement**" means that certain support agreement made between the Trust and EEC;

"**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 dated effective January 1, 2004, between Enterra and JED;

"**Trust**" means Enterra Energy Trust;

"**Trust Indenture**" means the amended and restated trust indenture dated November 25, 2003 among Olympia Trust Company, as trustee, Luc Chartrand as settler, and Enterra Energy, 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**" means units of the Trust;

"**Trustee**" means the trustee of Enterra, 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;

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

"**Voting and Exchange Trust Agreement**" means the voting and exchange trust agreement entered into between the Trust and EEC, and Olympia Trust Company; and

"**Voting and Exchange Trust Agreement Trustee**" means Olympia Trust Company, the initial trustee under the Voting and Exchange Trust Agreement, or such other trustee from time to time appointed thereunder.

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Abbreviations, Conventions and Conversions

Abbreviations

Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mmcf	million cubic feet
Mbbl	thousand barrels	Bcf	billion cubic feet
bbl/d	barrels per day	mcf/d	thousand cubic feet per day
NGLs	natural gas liquids	mmcf/d	million cubic feet per day
GJ	gigajoule	MMBTU	million British Thermal Units
GJ/d	gigajoule per day		

AECO-C	Intra-Alberta Nova Inventory Transfer Price (NIT net price)
API	American Petroleum Institute
°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
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil (Disclosure provided herein in respect to BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.)
BOE/d	barrel of oil equivalent per day
M^3	cubic metres
Mboe	1,000 barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
MW/h	Megawatts per hour

Conventions

Unless otherwise indicated, all dollar amounts are in Canadian dollars and references herein to "$" or "dollars" are to Canadian dollars.

The information set out in this annual information form is stated as at December 31, 2005 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

Exchange Rate Information

Except where otherwise indicated, all dollar amounts in this Annual Information Form are stated in Canadian dollars. The following table sets forth the US/Canada exchange rates on the last trading day of the years indicated as well as the high, low and average rates for such years. The high, low and average exchange rates for each year were identified or calculated from spot rates in effect on each trading day during the relevant year. The exchange rates shown are expressed as the umber of US dollars required to purchase one Canadian dollar. These exchange rates are based on those published on the Bank of Canada's website as being in effect at approximately noon on each trading day (the "Bank of Canada noon rate").

	Year Ended December 31		
	2005	**2004**	**2003**
Year End	0.8577	0.8308	0.7738
High	0.86090	0.8493	0.7738
Low	0.7872	0.7159	0.6350
Average	0.8258	0.7697	0.7156

Note Regarding Forward Looking Statements

Certain statements contained in this annual information form and in documents incorporated by reference constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements. Management believes the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included herein should not be unduly relied upon. These statements speak only as of the date hereof.

In particular, this annual information form contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this annual information from:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to realize the anticipated benefits of acquisitions; and
- the other factors discussed under "Risk Factors".

These factors should not be construed as exhaustive. We do not undertake any obligation to publicly update or revise any forward-looking statements.

Structure of Enterra Energy Trust

Enterra Energy Trust

Enterra is an oil and natural gas income trust established under the laws of the province of Alberta and pursuant to the Trust Indenture created as of November 25, 2003. Enterra's assets consist of the securities of the Trust Subsidiaries and indirect interests in crude oil and natural gas properties through its Operating Subsidiaries. The Trust's principal and head office is located at Suite 2600, 500 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6. The Trustee's head office is located at Suite 2300, 125 - 9th Avenue S.E., Calgary, Alberta, Canada T2G 0P6. Enterra's focus is to improve the quality of assets that underwrite the Unitholders' value and future distributions. The Trust pays monthly cash distributions on the 15th day of each month to Unitholders of record on the immediately preceding distribution record date. The business strategy is to maintain and enhance our oil and natural gas reserves to provide long-term sustainable cash distributions to Unitholders.

Enterra Energy Commercial Trust

EECT is an unincorporated commercial trust established by the laws of the province of Alberta. All of the issued and outstanding EECT Units are owned by the Trust. EECT, directly or indirectly, holds all of the outstanding shares and interests of the Operating Subsidiaries.

Enterra Energy Corp.

EEC is a corporation formed under the laws of the province of Alberta. EEC is one of the Operating Subsidiaries and was formed as a result of the completion of Enterra Arrangement. Pursuant to the Enterra Arrangement, former holders of common shares of Old Enterra received two trust units of the Trust or two EEC exchangeable shares, in accordance with the elections made by such holders, and Old Enterra became a wholly-owned subsidiary of the Trust. Old Enterra was subsequently amalgamated with Enterra Acquisition Corp., Big Horn Resources Ltd. and Enterra Sask. Ltd. to form EEC. At the same time, EEC became the administrator of the Trust pursuant to an administration agreement between the Trust and 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.

Rocky Mountain Acquisition Corp.

RMAC is a corporation formed under the laws of Alberta. Some of the crude oil and natural gas properties and related assets in which the Trust has an indirect interest are held, directly or indirectly, through RMAC. As at January 1, 2006, High Point and its subsidiaries were amalgamated into RMAC. The amalgamated entity changed its name to Enterra Production Corp. See "General Developments of Enterra Energy Trust - *Acquisition of High Point Resources Inc.* ".

Organizational Chart

The following chart illustrates the organization and structure of Enterra as at December 31, 2005:

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General Developments of Enterra Energy Trust

Historical Overview

History of Old Enterra Prior to the Enterra Arrangement

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

The Enterra Arrangement

The Enterra Arrangement received the approval of 99.37% of the votes cast by shareholders at a special meeting held on November 24, 2003 as well as the approval of the Court of Queen's Bench of Alberta on November 24, 2003 and became effective on November 25, 2003. Pursuant to the Enterra Arrangement, the outstanding common shares of Old Enterra were exchanged by the shareholders thereof for an aggregate of 18,951,556 Trust Units. In addition, as part of the Enterra Arrangement, Enterra Energy issued an aggregate of 2,000,000 EEC Exchangeable Shares to former holders of Old Enterra common shares in accordance with elections made by such holders under the Enterra Arrangement. Each EEC Exchangeable Share may be exchanged into Trust Units at any time.

The Trust Units commenced trading on the NASDAQ National Market System under the symbol "EENC" and the Toronto Stock Exchange ("TSX") under the symbol "ENT.UN" on November 28, 2003.

2004 Acquisition of assets

On January 30, 2004 the Trust completed the acquisition, from an unrelated oil and gas company, of properties in central Alberta. The purchase price, after final adjustments was $19.6 million. Upon closing, the acquisition added 1,800 BOE/d of net production, consisting of 1,600 bbl/d of oil and 1,200 mcf/d of gas along with 22,166 gross acres of undeveloped land.

Acquisition of Rocky Mountain Energy Corp.

On September 29, 2004 the Trust, through its subsidiary RMAC, completed the acquisition of RMEC by way of a plan of arrangement whereby RMAC acquired all the issued and outstanding common shares of RMEC. The transaction was valued at approximately $50.3 million. RMEC shareholders received approximately 86% of the consideration in the form of Trust Units and RMAC Exchangeable Shares and 14% in cash. The Trust and RMAC issued 1,946,576 Trust Units and 341,882 RMAC Exchangeable Shares, respectively. The acquisition of RMEC added approximately 1,000 BOE/d of production to Enterra together with the potential to drill over 22 additional wells.

2005 Acquisition of assets

On January 26, 2005, the Trust acquired certain oil and natural gas properties in east central Alberta for consideration of $12.1 million.

Acquisition of Rocky Mountain Gas, Inc.

On June 1, 2005, the Trust acquired 100% of the issued and outstanding shares of RMG, an entity with natural gas properties in Montana and Wyoming. RMG provides the Trust with future cash potential through the exploitation of coal bed methane on its undeveloped land as well as its currently producing assets. Results from operations of RMG subsequent to June 1, 2005 are included in the Trust's consolidated financial statements. The transaction was valued at approximately $24.0 million. The transaction was financed with 736,842 RMG Exchangeable Shares valued at $16.7 million, 275,474 Trust Units valued at $6.3 million and cash of $1.0 million.

Acquisition of High Point Resources Inc.

On August 17, 2005 the Trust completed the acquisition of 100% of the common shares of High Point through its subsidiary, RMAC, in exchange for 7,490,898 Trust Units and 1,407,177 RMAC Exchangeable Shares. High Point's oil and natural gas properties are predominantly in Alberta and British Columbia. The acquisition was completed to increase Enterra 's natural gas portfolio, provide strong cash flows and significant tax pools. For further information on this acquisition, see the following, each of which is available on SEDAR at www.sedar.com and is incorporated herein by reference:

- the audited consolidated financial statements of High Point as at and for the financial years ended December 31, 2004 and 2003 (including comparative year ended December 31, 2002), together with the notes thereto and the auditors' reports thereon;

- the unaudited consolidated financial statements of High Point as at and for the six months ended June 30, 2005 (including the comparative financial statements contained therein) together with the notes thereto respecting such time period;

- the statement of reserves data and other oil and gas information of High Point presented on pages 11 to 28 of High Point's renewal annual information form dated March 21, 2005 for the year ended December 31, 2004;

- the recent developments disclosure of High Point presented on pages 50 to 54 of High Point's information circular and proxy statement dated July 18, 2005 relating to the special meeting of shareholders held on August 16, 2005; and

- the material change report of the Trust dated August 24, 2005 with respect to the completion of acquisition of High Point.

2006 Acquisition of assets - Oklahoma

During the first quarter of 2006, the Trust acquired approximately 5,000 BOE/d of producing assets located in Oklahoma. The Trust expects to complete a final closing for additional working interests in the properties representing approximately 1,300 BOE/day. The assets consist of approximately 80% natural gas and 20% light oil and include over 53,000 net acres of land of which over 25,000 net acres are undeveloped.

The purchase price of USD $221.0 million was paid for through the issuance of 5,178,792 Trust Units valued at USD $91.7 million, cash of USD $102.3 million and USD $27.0 million of assumed debts. Certain post closing purchase price adjustment provisions remain in place, based on production rates achieved from the assets through September 19, 2006. The purchase price on the final closing of the additional working interests will be paid with a combination of units and cash.

The current and anticipated production from these assets is 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 is exploited at depths of approximately 1,500 metres using long, multi-leg horizontal wells. The Trust will operate all of its production, gathering and water disposal facilities. A staff of approximately thirty will join the Trust when the final transactions are complete.

Enterra has announced a farm out agreement with Petroflow Energy Ltd. to exploit the undeveloped Hunton prospects aggressively in 2006.

All the developed and undeveloped lands are overlain by the Woodford Shale, which is speculated to be a prospective shale gas target similar to the Barnett Shale in Texas. Enterra's long term plans include testing of this concept. For further information of this acquisition, see the Trust's amended and restated material change report dated February 28, 2006, which is available on SEDAR at www.sedar.com and is incorporated herein by reference.

Equity offerings

On January 16, 2004 Enterra entered into a financing agreement whereby it agreed to issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$16.5 million. The funds received from this financing were applied to pay down debt and for general corporate purposes. The financing closed on June 29, 2004.

On February 20, 2004 Enterra completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11.8 million (US$10.3 million net of financing costs). Funds received were applied to repay debt.

On March 4, 2005 Enterra completed a private placement of 500,000 Trust Units at a price of US$19.00 for gross proceeds of US$9.5 million. The funds received from this financing were applied to pay down debt and for general corporate purposes.

On April 22, 2005, Enterra entered into an equity line of credit arrangement with Kingsbridge Capital Limited whereby they has committed to purchase up to US$100.0 million of Trust Units in various draw downs at the option of the Trust. As at December 31, 2005, the Trust had issued 689,087 Trust Units for proceeds of Cdn$15.8 million.

On December 20, 2005 the Trust filed a Prospectus Supplement for the issuance of up to 950,000 Trust Units at US$16.00 per unit. The issuances under the Prospectus Supplement had to be completed by January 13, 2006. The Trust issued 882,500 Trust Units under this supplement.

Operational Information

Overview

The Trust's operation strategy is to improve the quality of assets that underwrite the Unitholders' value and future distributions. The acquisition of High Point in August 2005 was the first significant step along this path. Rigorous processes have been and are being established to ensure strict cost accountability and regulatory compliance in all aspects of the business. These significant changes are ongoing in 2006.

The Trust's business strategy is to maintain and enhance our oil and natural gas reserves to provide long-term sustainable cash distributions to Unitholders. The Trust uses a three-pronged strategy to achieve its goals through acquisition of producing properties with extensive potential for additional development upside, the use of strategic farm outs to develop these properties, and the pre-agreed acquisition from the farmee of the production resulting from these farm outs. Acquisitions are financed with cash flow, equity and with debt, the optimal mix being one that provides for the strongest balance sheet, and hence the maximum accretion of value to the Unitholders. The Trust's ability to replace and grow quality reserves using these strategies is a key success factor in our business outcomes.

The Trust also looks over time to improve the efficiency of its portfolio via a focus on higher quality products such as light oil and natural gas, and through the rationalization of assets with higher operating costs. Future growth will be financed with a combination of retained cash flow from operating activities, drawing from our credit facilities, and the issuance of Trust Units. The level of distribution to Unitholders will fluctuate depending on a number of factors, including future commodity prices and operating results. The portion of cash not distributed to Unitholders will be used for maintenance of capital or reduction of bank debt.

Personnel

At December 31, 2005, Enterra employed 24 office employees and 33 field operations employees for a total of 57 employees.

Risk Management
We are exposed to all of the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure to such risks.

Credit Risk
Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of Enterra's accounts receivable is with customers in the energy industry and is subject to normal industry credit risk. The Trust assesses the financial strength of its customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk
Enterra is exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Monthly distributions are also based on a value expressed in U.S. dollars. However, significant operating expenses, drilling expenses and general overhead expenses are incurred in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect the Trust. When the value of the U.S. dollar increases, the Trust receives higher revenue and when the value of the U.S. dollar declines, the Trust receives lower revenue on the same amount of production sold at the same prices. Based on results of 2005, a change of $0.01 in the U.S. to Cdn dollar in 2006 would impact the Trust's earnings by approximately $1.9 million and our cash provided by operating activities by $1.2 million.

Commodity price risk
The financial condition, results of operations and capital resources of Enterra are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the Trust's control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect the Trust's financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that the Trust can produce economically. Any reduction in the Trust's oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on the Trust's ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favourable impact on the Trust's financial condition, results of operations and capital resources. Based on the results of 2005, if the WTI oil price were to change by US$1.00 per bbl in 2006, the impact on earnings would be approximately $1.8 million and the impact on cash flow would be approximately $2.9 million. If natural gas prices were to change by US$0.50 per mcf, the impact on earnings would be approximately $1.4 million and the impact on cash provided by operating activities would be approximately $2.3 million.

Enterra uses financial derivatives and physical sales contracts to mitigate a portion of oil and natural gas price risk. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits that may be derived from price increases.

Enterra had several collars and forward contracts in place during the year in order to minimize the volatility in crude oil and natural gas pricing. Below is a summary of our hedging operations as of December 31, 2005:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Floors	Gas	9.65 to 9.80	10,000 GJ	January 1, 2006 - April 1, 2006
Collars	Gas	8.50 to 14.00	10,000 GJ	April 1, 2006 - November 1, 2006
Collars	Oil	55.00 to 80.00	1,000 bbl	January 1, 2006 - January 1, 2007
Collars	Oil	55.00 to 80.00	1,000 bbl	April 1, 2006 - January 1, 2007

At December 31, 2005, we had the following fixed price physical delivery contracts outstanding:

	Contract Period End	Quantity	Pricing
Natural Gas Contracts	March 31, 2006	8,000 GJ/day	$8.01 to $8.85

Interest Rate Risk

Interest rate risk exists principally with respect to indebtedness that bears interest at floating rates. At December 31, 2005, the Trust had $95.5 million of indebtedness bearing interest at floating rates. Based on results of 2005, if interest rate were to change by one full percentage point in 2006, the net impact on earnings would be approximately $0.6 million and the net impact on our cash provided by operating activities would be approximately $1.0 million.

Summary of Risk Sensitivities

Summarized below are the Trust's sensitivities to various risks, based on its 2005 operations:

Sensitivity	Estimated 2006 Impact On: ('000s)	
	Net Earnings	Cash Flow
Crude oil - US$1.00/bbl change in WTI	1,822	2,921
Natural gas - US$0.50/mcf change	1,447	2,320
Foreign exchange - $0.01 change in U.S. to Cdn dollar	1,888	1,178
Interest rate - 1% change	595	955

Revenue Sources

For the year ended December 31, 2005, approximately 30% of the revenue from our properties was derived from natural gas and approximately 70% was derived from crude oil and natural gas liquids.

Statement of Reserves Data and Other Oil and Gas Information

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluations conducted by McDaniel with an effective date of December 31, 2005 contained in the McDaniel Report and by Sproule with an effective date December 31, 2005 contained in the Sproule Report. The Reserves Data summarizes the oil, NGL and natural gas reserves of Enterra and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The McDaniel Report and Sproule Report have been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Enterra engaged McDaniel and Sproule to provide an evaluation of its proved and proved plus probable reserves.

At December 31, 2005 Enterra's reserves were in Canada and, specifically, in the provinces of Alberta, Saskatchewan and Manitoba, and in the United States, specifically in the state of Wyoming. McDaniel reviewed the reserves in Canada and Sproule reviewed the reserves in Wyoming.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimate future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the properties of the Trust. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue

The tables below are a summary of the oil, NGL and natural gas reserves of the Trust and the net present value of future net revenue attributable to such reserves as evaluated by McDaniel and Sproule based on constant and forecast price and cost assumptions. The tables summarize the data contained in the McDaniel Report and Sproule Report. Gross reserves include royalty interests. The data may contain slightly different numbers than such report due to rounding. Additionally, the numbers in the tables may not add exactly due to rounding.

The McDaniel Report and Sproule Report are based on certain factual data supplied by the Trust and McDaniel's and Sproule's opinions of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Trust's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Trust to McDaniel and Sproule and accepted without any further investigation.

Reserves Data - Constant Prices and Costs

Summary of Oil and Gas Reserves and
Net Present Values of Future Net Revenue
As of December 31, 2005
Constant Prices and Costs

	Remaining Reserves									
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids		Natural Gas		Total	
Reserves Category	Gross [mbbl]	Net [mbbl]	Gross [mbbl]	Net [mbbl]	Gross [mbbl]	Net [mbbl]	Gross [mmcf]	Net [mmcf]	Gross [mboe]	Net [mboe]
CANADA (McDaniels Report)										
Proved										
Developed Producing	3,621	3,162	1,287	1,145	1,120	783	33,952	25,342	11,687	9,313
Developed Non-Producing	4	4	-	-	143	103	5,887	4,323	1,128	828
Undeveloped	53	47	-	-	142	99	4,634	3,430	968	717
Total Proved	3,679	3,213	1,287	1,145	1,405	985	44,473	33,095	13,783	10,858
Probable	1,150	991	422	365	523	367	15,595	11,717	4,694	3,675
Total Proved Plus Probable	4,829	4,204	1,709	1,510	1,928	1,352	60,068	44,812	18,477	14,533
UNITED STATES (Sproule Report)										
Proved										
Developed Producing	-	-	-	-	-	-	2,926	1,601	488	267
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	-	-	-	-	-	2,926	1,601	488	267
Probable	-	-	-	-	-	-	254	101	42	17
Total Proved Plus Probable	-	-	--	-	-	-	3,180	1,701	530	284
AGGREGATE										
Proved										
Developed Producing	3,621	3,162	1,287	1,145	1,120	783	36,878	26,943	12,175	9,580
Developed Non-Producing	4	4	-	-	143	103	5,887	4,323	1,128	828
Undeveloped	53	47	-	-	142	99	4,634	3,430	968	717
Total Proved	3,678	3,213	1,287	1,145	1,405	985	47,399	34,696	14,271	11,125
Probable	1,150	991	422	365	522	367	15,849	11,818	4,736	3,692
Total Proved Plus Probable	4,829	4,204	1,709	1,510	1,928	1,352	63,248	46,514	19,007	14,817

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Reserves Data - Constant Prices and Costs

Summary of Oil and Gas Reserves and
Net Present Values of Future Net Revenue
As of December 31, 2005
Constant Prices and Costs

	Net Present Values of Future Net Revenue Constant Prices and Costs									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
	0	5	10	15	20	0	5	10	15	20
Reserves Category	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]
CANADA (McDaniel's Report)										
Proved										
Developed Producing	378.9	320.0	279.1	249.1	226.0	327.9	278.5	244.3	219.1	199.8
Developed Non-Producing	40.3	36.0	32.7	30.0	27.8	26.5	23.7	21.4	19.6	18.2
Undeveloped	39.2	32.5	27.8	24.4	21.8	25.7	21.3	18.2	16.0	14.3
Total Proved	458.4	388.5	339.6	303.5	275.6	380.1	323.5	283.9	254.7	232.3
Probable	173.7	122.9	94.0	75.7	63.3	115.7	81.5	62.2	50.1	41.8
Total Proved Plus Probable	632.1	511.4	433.6	379.2	338.9	495.8	405.0	346.1	304.8	274.1
UNITED STATES (Sproule Report)										
Proved										
Developed Producing	4.9	4.6	4.3	4.1	3.9	3.2	3.0	2.8	2.7	2.5
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	4.9	4.6	4.3	4.1	3.9	3.2	3.0	2.8	2.7	2.5
Probable	0.2	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0
Total Proved Plus Probable	5.1	4.7	4.4	4.2	4.0	3.3	3.1	2.9	2.7	2.6

Note: An exchange rate of $0.85US/CDN was used to convert Sproule US values to Canadian dollars

AGGREGATE										
Proved										
Developed Producing	383.8	324.6	283.4	253.2	229.9	331.1	281.5	247.1	221.8	202.3
Developed Non-Producing	40.3	36.0	32.7	30.0	27.8	26.5	23.7	21.4	19.6	18.2
Undeveloped	39.2	32.5	27.8	24.4	21.8	25.7	21.3	18.2	16.0	14.3
Total Proved	463.3	393.1	343.9	307.6	279.5	383.3	326.5	286.7	257.4	234.8
Probable	173.9	123.0	94.1	75.8	63.3	115.8	81.6	62.3	50.1	41.8

Total Proved Plus Probable	637.2	516.1	438.0	383.4	342.9	499.1	408.1	349.0	307.5	276.7

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Total Future Net Revenue
(Undiscounted)
As of December 31, 2005
Constant Prices and Costs

Reserves Category	Revenue [$mm]	Royalties Net of ARTC [$mm]	Operating Costs [$mm]	Capital Development Costs [$mm]	Abandonment Costs [$mm]	Future Net Revenue Before Income Taxes [$mm]	Income Taxes [$mm]	Future Net Revenue After Income Taxes [$mm]
CANADA (McDaniel's Report)								
Total Proved	790.8	159.6	147.2	7.2	18.4	458.5	78.4	380.1
Total Proved Plus Probable	1,062.9	215.3	189.1	7.9	18.4	632.1	136.3	495.8
UNITED STATES (Sproule Report)								
Total Proved	10.6	1.3	3.5	-	0.9	4.9	1.7	3.2
Total Proved Plus Probable	11.2	1.4	3.8	-	0.9	5.1	1.8	3.3
AGGREGATE								
Total Proved	801.4	160.9	150.7	7.2	19.3	463.4	80.1	383.3
Total Proved Plus Probable	1,074.1	216.7	192.9	7.9	19.3	637.2	138.1	499.1

Future Net Revenue by Production Group
As of December 31, 2005
Constant Prices and Costs

Reserves Category	Future Net Revenue Before Income Taxes and Discounted at 10% [$mm]
Proved	
Light and Medium Crude Oil (1)	100.6
Heavy Oil	14.1
Natural Gas (2)	221.4
Total(3)	336.1
Proved Plus Probable	
Light and Medium Crude Oil (1)	129.6
Heavy Oil	18.8
Natural Gas (2)	281.1
Total(3)	429.5

Notes:(1) Including by-products, but excluding solution gas from oil wells

(2) Including solution gas and other by-products
(3) Excludes ARTC

Reserves Data - Forecast Prices and Costs

Summary of Oil and Gas Reserves and
Net Present Values of Future Net Revenue
As of December 31, 2005
Forecast Prices and Costs

	Remaining Reserves									
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids		Natural Gas		Total	
Reserves Category	Gross [mbbl]	Net [mbbl]	Gross [mbbl]	Net [mbbl]	Gross [mbbl]	Net [mbbl]	Gross [mmcf]	Net [mmcf]	Gross [mboe]	Net [mboe]
CANADA (McDaniel Report)										
Proved										
Developed Producing	3,624	3,165	1,292	1,146	1,121	784	33,986	25,371	11,701	9,322
Developed Non-Producing	4	4	-	-	143	103	5,877	4,320	1,127	827
Undeveloped	53	47	-	-	142	99	4,634	3,435	968	719
Total Proved	3,681	3,216	1,292	1,146	1,406	986	44,497	33,126	13,796	10,868
Probable	1,148	985	421	364	524	367	15,610	11,716	4,695	3,669
Total Proved Plus Probable	4,829	4,201	1,713	1,510	1,930	1,353	60,107	44,842	18,491	14,537
UNITED STATES (Sproule Report)										
Proved										
Developed Producing	-	-	-	-	-	-	2,926	1,601	488	267
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	-	-	-	-	-	2,926	1,601	488	267
Probable	-	-	-	-	-	-	254	101	42	17
Total Proved Plus Probable	-	-	-	-	-	-	3,180	1,701	530	284
AGGREGATE										
Proved										
Developed Producing	3,624	3,165	1,292	1,146	1,121	784	36,912	26,972	12,189	9,589
Developed Non-Producing	4	4	-	-	143	103	5,877	4,320	1,127	827
Undeveloped	53	47	-	-	142	99	4,634	3,435	968	719
Total Proved	3,681	3,216	1,292	1,146	1,406	986	47,423	34,727	14,284	11,135
Probable	1,148	985	421	364	524	367	15,864	11,817	4,737	3,686

Total Proved Plus Probable	4,829	4,201	1,713	1,510	1,930	1,353	63,287	46,544	19,021	14,821

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Reserves Data - Forecast Prices and Costs

Summary of Oil and Gas Reserves and
Net Present Values of Future Net Revenue
As of December 31, 2005
Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
	0	5	10	15	20	0	5	10	15	20
Reserves Category	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]	[$mm]
CANADA (McDaniel Report)										
Proved										
Developed Producing	322	279	249	227	209	290	252	225	204	189
Developed Non-Producing	33	30	28	26	24	21	20	18	17	16
Undeveloped	32	27	24	21	19	21	18	16	14	13
Total Proved	387	336	301	274	252	332	289	258	235	217
Probable	139	99	77	63	53	93	66	51	41	35
Total Proved Plus Probable	526	435	378	337	305	425	355	309	277	252
UNITED STATES (Sproule Report)										
Proved										
Developed Producing	5.9	5.5	5.2	4.9	4.6	3.9	3.5	3.3	3.1	3.0
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	5.9	5.5	5.2	4.9	4.6	3.9	3.5	3.3	3.1	3.0
Probable	0.3	0.2	0.2	0.1	0.1	0.2	0.2	0.1	0.1	0.1
Total Proved Plus Probable	6.2	5.7	5.4	5.0	4.7	4.1	3.7	3.4	3.2	3.1

Note: An exchange rate of $0.85US/CDN was used to convert Sproule US values to Canadian dollars.

AGGREGATE										
Proved										
Developed Producing	327.9	284.5	254.2	231.9	213.6	274.9	236.5	209.3	190.1	174.0
Developed Non-Producing	33	30	28	26	24	21	20	18	17	16
Undeveloped	32	27	24	21	19	21	18	16	14	13
Total Proved	392.9	341.5	306.2	278.9	256.6	316.9	274.5	243.3	221.1	203.0
Probable	139.3	99.2	77.2	63.1	53.1	93.2	66.2	51.1	41.1	35.1

Total Proved Plus Probable	532.2	440.7	383.4	342.0	309.7	429.1	358.7	312.4	280.2	255.1

Total Future Net Revenue
(Undiscounted)
As of December 31, 2005
Forecast Prices and Costs

Reserves Category	Revenue [$mm]	Royalties Net of ARTC [$mm]	Operating Costs [$mm]	Capital Development Costs [$mm]	Abandonment Costs [$mm]	Future Net Revenue Before Income Taxes [$mm]	Income Taxes [$mm]	Future Net Revenue After Income Taxes [$mm]
CANADA (McDaniel's Report)								
Total Proved	725.2	142.3	166.1	7.4	23.0	386.4	54.0	332.4
Total Proved Plus Probable	967.8	189.4	220.4	8.3	24.0	525.7	100.2	425.5
UNITED STATES (Sproule Report)								
Total Proved	12.2	1.5	3.9	-	1.0	5.8	2.1	3.7
Total Proved Plus Probable	13.0	1.6	4.2	-	1.0	6.2	2.2	4.0
AGGREGATE								
Total Proved	737.4	143.8	170.0	7.4	24.0	392.2	56.1	336.1
Total Proved Plus Probable	980.8	191.0	224.6	8.3	25.0	531.9	102.4	429.9

Future Net Revenue by Production Group
As of December 31, 2005
Forecast Prices and Costs

Reserves Category	Future Net Revenue Before Income Taxes and Discounted at 10% [$mm]
Proved	
Light and Medium Crude Oil (1)	96.1
Heavy Oil	16.5
Natural Gas (2)	185.2
Total(3)	297.8
Proved Plus Probable	
Light and Medium Crude Oil (1)	121.1
Heavy Oil	21.5
Natural Gas (2)	231.4
Total(3)	374.0

Notes: (1) Including by-products, but excluding solution gas from oil wells

(2) Including solution gas and other by-products
(3) Excludes ARTC.

Pricing Assumptions(1)
Constant Prices and Costs

Year	WTI at Cushing [$US/bbl]	Edmonton Par Price 40°API [$Cdn/bbl]	Bow River Medium 25°API [$Cdn/bbl]	Cromer Medium [$Cdn/bbl]	US Henry Hub Gas Price $US/Mmbtu	US Actual Gas Price $US/Mmbtu	Alberta Average Plant gate Price [$Cdn/Mmbtu]	Natural Gas Liquids FOB Edmonton [$Cdn/bbl]	US/CAN Exchange Rate $US/$Cdn
2005(Year end)	61.04	68.46	36.71	51.65		7.72	9.80	56.30	0.830

(1) Pricing assumptions are the same for both the Sproule Report and the McDaniel Report.

Pricing Assumptions(1)
Forecast Prices and Costs

Year	WTI at Cushing [$US/bbl]	Edmonton Par Price 40°API [$Cdn/bbl]	Bow River Medium 25°API [$Cdn/bbl]	Alberta Heavy 12°API [$Cdn/bbl]	US Henry Hub Gas Price $US/Mmbtu	Alberta Average Plant gate Price [$Cdn/Mmbtu]	Natural Gas Liquids FOB Edmonton [$Cdn/bbl]	Inflation %	US/CAN Exchange Rate $US/$Cdn
2005 (est.)	56.45	69.05	45.00	34.55	8.50	8.60	50.10	2.0	0.825
Forecast									
2006	57.50	66.60	45.70	35.50	9.90	10.40	51.40	2.5	0.850
2007	55.40	64.20	45.30	36.10	9.05	9.35	48.90	2.5	0.850
2008	52.50	60.70	44.00	36.00	8.15	8.30	45.80	2.5	0.850
2009	49.50	57.20	42.60	35.30	7.25	7.20	42.60	2.5	0.850
2010	46.90	54.10	40.30	33.40	6.85	6.70	40.20	2.5	0.850
2011	48.10	55.50	41.30	34.20	7.05	6.85	41.30	2.5	0.850
2012	49.30	56.80	42.30	35.10	7.25	7.05	42.20	2.5	0.850
2013	50.50	58.20	43.40	35.90	7.40	7.20	43.20	2.5	0.850
2014	51.80	59.70	44.50	36.90	7.60	7.40	44.30	2.5	0.850
2015	53.10	61.20	45.60	37.80	7.80	7.60	45.50	2.5	0.850
2016	54.40	62.70	46.70	38.70	7.95	7.75	46.60	2.5	0.850
2017	55.80	64.30	47.90	39.70	8.20	8.00	47.80	2.5	0.850
2018	57.20	65.90	49.10	40.70	8.40	8.20	49.00	2.5	0.850
2019	58.60	67.60	50.30	41.70	8.60	8.35	50.20	2.5	0.850
2020	60.10	69.30	51.60	42.80	8.80	8.55	51.50	2.5	0.850
Thereafter	+2.5%/yr	+2.5%/yr	+2.5 yr %/	+2.5 yr %/	+2.5%/yr	+2.5%/yr	+2.5%/yr	2.5	0.850

(1) Pricing assumptions are the same for both the Sproule Report and the McDaniel Report.

Reserves Reconciliation

Reconciliation of Company Net Reserves by Product Type
As of December 31, 2005
Forecast Prices and Costs

	Light and Medium Crude Oil			Natural Gas Liquids		
	Total Proved Reserves [mbbl]	Probable Reserves [mbbl]	Total Proved Plus Probable [mbbl]	Total Proved Reserves [mbbl]	Probable Reserves [mbbl]	Total Proved Plus Probable [mbbl]
CANADA						
Opening balance - December 31, 2004	3,913.7	1,034.3	4,948.0	136.1	34.1	170.2
Discoveries	-	-	-	-	-	-
Technical revisions	432.8	-61.5	371.3	15.0	15.6	30.6
Acquisitions	44.6	12.6	57.2	922.2	317.2	1,239.4
Dispositions	-	-	-	-	-	-
Production	-1,175.4	-	-1,175.4	-87.6	-	-87.6
Closing balance - December 31, 2005	3,215.7	985.4	4,201.1	985.7	366.9	1,352.6
UNITED STATES						
Opening balance - December 31, 2004	-	-	-		-	-
Discoveries	-	-	-	-	-	-
Technical revisions	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Production	-	-	-	-	-	-
Closing balance - December 31, 2005	-	-	-	-	-	-
AGGREGATE						
Opening balance - December 31, 2004	3,913.7	1,034.3	4,948.0	136.1	34.1	170.2
Discoveries	-	-	-	-	-	-
Technical revisions	432.8	-65.8	371.3	14.0	15.6	29.6
Acquisitions	44.6	12.6	57.2	922.2	317.2	1,239.4
Dispositions	-	-	-	0.0	0.0	0.0
Production	-1,175.4	-	-1175.4	-87.6	0.0	-87.6
Closing balance - December 31, 2005	3,215.7	985.4	4,201.1	984.7	366.9	1,351.6

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Reserves Reconciliation

Reconciliation of Company Net Reserves by Product Type
As of December 31, 2005
Forecast Prices and Costs

	Associated and Non-Associated Gas			Heavy Oil		
	Total Proved Reserves [mmcf]	Probable Reserves [mmcf]	Total Proved Plus Probable [mmcf]	Total Proved Reserves [mbbl]	Probable Reserves [mbbl]	Total Proved Plus Probable [mbbl]
CANADA						
Opening balance - December 31, 2004	5,536.6	1,343.8	6,880.4	1,329.8	411.1	1,740.9
Discoveries	-	-	-	-	-	-
Technical revisions	-2,806.3	-1,103.5	-3,909.8	102.1	-47.0	55.1
Acquisitions	33,561.4	11,475.2	45,036.6	-	-	-
Dispositions	-	-	-	-	-	-
Production	-3,165.3	-	-3,165.3	-286.1	-	-286.1
Closing balance - December 31, 2005	33,126.4	11,715.5	44,841.9	1,145.8	364.1	1,509.9
UNITED STATES						
Opening balance - December 31, 2004	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Technical revisions	-408.1	-9,375.1	-9,783.2	-	-	-
Acquisitions	2,620.2	9,476.1	12,096.3	-	-	-
Dispositions	-	-	-	-	-	-
Production	-571.1	-	-571.1	-	-	-
Closing balance - December 31, 2005	1,641.0	101.0	1,742.0	-	-	-
AGGREGATE						
Opening balance - December 31, 2004	5,536.6	1,343.8	6,880.4	1,329.8	411.1	1,740.9
Discoveries	-	-	-	-	-	-
Technical revisions	-3,214.4	-10,478.6	-15,682.9	102.1	-47.0	55.1
Acquisitions	36,181.6	20,951.3	57,132.9	-	-	-
Dispositions	-	-	-	-	-	-
Production	-3,736.4	0.0	-3,736.4	-286.1	0.0	-286.1
Closing balance - December 31, 2005	34,767.4	11,816.5	46,583.9	1,145.8	364.1	1,509.9

Reconciliation of Changes in
Net Present Values of Future Net Revenue
Discounted at 10% Per Year
Proved Reserves
Constant Prices and Costs

	($M)
Estimated Future Net Revenue After Tax, December 31, 2004	81,120
Oil and Gas Sales During the Period Net of Royalties and Production Costs	(89,044)
Changes due to Prices	107,194
Changes in Future Development Costs	(21,869)
Development costs incurred during the year	23,101
Changes Resulting from Extensions, Infill Drilling and Improved Recovery	1,024
Changes Resulting from Discoveries	-
Changes Resulting from Acquisitions of Reserves	210,631
Changes Resulting from Dispositions of Reserves	-
Accretion of Discount	8,112
Other Significant Factors	-
Net Changes in Income Taxes	(39,068)
Changes Resulting from Technical Reserves Revisions Plus Effects of Timing	(5,576)
Estimated Future Net Revenue After Tax, December 31, 2005	**286,777**

Undeveloped Reserves
The Trust has 33 proved undeveloped locations primarily at the Ferrier and Desan fields. It has waterflood development in the Cummings "Y" pool.

Significant Factors or Uncertainties Affecting Reserves Data
The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. McDaniel and Sproule, independent engineering firms, evaluate the Trust's reserves.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only). Note all future development costs are associated with Canadian assets. There is no future development costs associated with the U.S. assets.

	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2006	6,984	7,158	7,466
2007	-	-	-
2008	-	-	-
2009	200	226	226
2010	-	-	-
Remaining Years	-	-	656
Total Undiscounted	7,184	7,384	8,349
Total Discounted at 10% per year	6,789	6,973	7,448

Common Infrastructure Costs

Under the revised farm-in arrangement with JED, JED will enter into a 3-year take or pay arrangement where the full cost of common infrastructure plus a 12% return on the investment will be recovered.

	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2006	6,600	6,766	6,766
Remaining Years	-	-	-
Total Undiscounted	6,600	6,766	6,766

The Trust estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. The Trust typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

The Trust expects to fund its total 2006 capital program with internally generated cash flow and equity and debt issuances.

Oil and Gas Properties

The Trust's core areas include a variety of assets in the Western Canada Sedimentary Basin in the Provinces of Alberta and British Columbia including the following major producing fields and areas in Alberta: Clair, Sylvan Lake, Provost-Alliance-Wainwright, Princess, Ricinus, Ferrier and Lochend. In the Province of British Columbia the Trust has a significant producing area at Desan. In the United States Enterra's significant producing assets include coal bed methane fields near Gillette, Wyoming and producing regions in Grant, Lincoln and Logan Counties in Oklahoma. The Trust also has in Alberta, British Columbia, Saskatchewan, Wyoming, Montana and Oklahoma, an inventory of minor producing assets, minor royalty interests, and various prospects of an exploitation and exploration nature on undeveloped lands, the development of which could significantly increase the size of our existing production and reserve base.

Clair, Alberta

The Clair property is located 7 miles north of Grande Prairie, Alberta. Enterra's assets include a 100% working interest in 3,520 acres of land, 23 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the Doe Creek (Dunvegan) formation with a small amount of gas production from the Charlie Lake and Halfway formations. Production is light, 44°API gravity crude oil and solution gas from the Doe Creek oil pool. One additional dually completed Charlie Lake and Halfway gas well also produces. At December 2005 there were 23 oil wells and one gas well producing a combined 1950 bbl/d of oil and 1400 mcf/d of raw solution gas on a working interest basis before royalties. To date, Enterra has drilled or re-completed 29 wells for oil and seven wells for water injection. There are no further drilling plans for the pool. The pool is currently being water flooded to optimize the recovery of hydrocarbons.

Total remaining net proved reserves assigned by McDaniel & Associates to the Doe Creek 'A' (Dunvegan) pool are 1,141 mbbl of oil, 955 mmcf of gas and 67 mbbl of natural gas liquids. Included in the total net proved reserves of Clair are reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well of 358 mmcf of gas and 24 mbbl of natural gas liquids.

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

Provost-Alliance-Wainwright, Alberta

The Provost-Alliance-Wainwright producing area is located near Provost, Alberta. Major areas within the package are Alliance, Sounding Lake, Hansman Lake, Halkirk, Monitor, Provost Cummings "Y" Unit and Wainwright. Enterra's assets include an average working interest of 80% in 84,454 gross acres of land as well as 371 producing oil and gas wells. Production is obtained primarily from the Dina, Cummings and Belly River formations. Enterra's December share of current production for the entire area is 1,513 bbl/d of oil and NGLs and 1,563 mcf/d of gas on a working interest basis before royalties. In order to optimize production and lower operating costs, Enterra has and continues to optimize down hole pumps to maximize oil production and upgrade or consolidate oil batteries to handle higher volumes of total fluid and injection water. Solution gas is currently conserved at most of the oil batteries.

In 2004 and 2005 Enterra with its partner JED Oil Inc. drilled 21 oil wells in the Cummings "Y" Unit to bring the total number of oil producers to 37. In order to lower operating costs and optimize reserve recovery from the Cummings "Y" pool, Enterra constructed a central facility to ship clean oil and re-inject produced water into the pool. Significant field performance improvements will result from full activation of the water flood in 2006.

McDaniel & Associates assigned net proved reserves in the Provost-Alliance-Wainwright area of 1787 mbbl of oil, 2,450 mmcf of natural gas and 32.4 mbbl of natural gas liquids.

Princess area

The Princess area assets were acquired from RMEC, and are now being operated under RMAC. Our working interest is 54% in 27,747 acres in the Princess area. Production is primarily from the Sunburst and Pekisko formations. Sunburst production consists of gas and 23°API crude oil. The Pekisko production consists of gas and 27°API crude oil. RMAC has an average working interest of 50% of 3,040 acres in the Tide Lake area. Production, consisting of 27°API oil, is from the Pekisko formation. In December 2005, total area working interest production before royalties was 516 bbl/d of oil and NGLs and 1206 mcf/d gas.

McDaniel & Associates has assigned total net proved remaining reserves of 524 mbbl of oil, 1,163 mmcf of natural gas and 17 mbbl of natural gas liquids.

Sylvan Lake

The Sylvan Lake property is located 24 miles west of the town of Red Deer, Alberta. Enterra's assets include an average working interest of 64% in 4312 gross acres of land as well as 25 producing oil wells. Enterra completed the development of 40-acre spacing wells in the Pekisko G pool, and also drilled four subsequent oil wells on 20 acre spacing. At December 2005, the field was producing 553 bbl/day of 14 degree API oil with 413 mcf/d of associated gas. Production is flow lined into an Enterra operated central treating facility. Non-associated gas is conserved and flow lined to the Husky Sylvan Lake gas plant. Clean oil is trucked from the facility to sales.

McDaniel & Associates has assigned total proved remaining reserves of 981 mbbl of oil, 991 mmcf of natural gas, 52 mbbl of natural gas liquids. Studies are being undertaken in 2006 to optimize the water flood of the field to improve oil recovery.

Ferrier

The Ferrier property is located in west central Alberta where Enterra operates as well as conducts joint venture operations with other companies. The productive horizons are multi-zone liquids rich natural gas formations at depths ranging from 2,400 meters to 2,800 meters. The majority of the area has year round access for drilling, seismic and construction projects.

Enterra owns various interests in 51 sections of land. The area is mainly developed at two wells per section for gas and four wells per section for oil. Since acquiring the High Point assets, the Trust has farmed out the drilling of 15 wells, with eight on production and one awaiting tie-in. Enterra owns infield compression and dehydration facilities and pipelines in proportion to its well interests. The raw gas is processed at third party processing facilities to remove natural gas liquids. Enterra's average net production for this area for December 2005 was 4.4 mmcf/d of natural gas and 250 bbl/d of oil and natural gas liquids.

McDaniel & Associates has assigned total proved reserves of 13.7 bcf of natural gas and 799 mbbls of oil and NGLs.

Ricinus
The Ricinus property is located in west central Alberta south of the Ferrier area. Enterra has interests varying from 6.5% to 85 per cent in 43 sections of land. Ricinus is a major exploitation area for Enterra, targeting sweet light oil and gas to depths of 3,000 meters. Since the acquisition of High Point, seven wells have been drilled under farm out terms and three are on production, with three awaiting tie-in and one well that was abandoned. Enterra operates the property. Enterra's average net production for this area for December 2005 was 1.3 mmcf/d of natural gas and 104 bbls/d of oil and natural gas liquids.

McDaniel & Associates has assigned total proved reserves of 3.9 bcf of natural gas and 205 mbbls of oil to the Ricinus shallow horizons.

Within the Ricinus area, Enterra has a 50% interest in one deep, high productivity Leduc well anticipated to begin production in April 2006. McDaniel & Associates has assigned additional proved plus probable gas reserves of 4.5 bcf to this well. One or two additional drill targets of a similar nature may exist on our lands.

Lochend
The Lochend property is located west central Alberta south of Ricinus. Enterra has a 21 per cent interest in 16 sections of land. The property has undergone extensive development over the last three years with 29 wells currently producing. The property is being developed at four wells per section for light oil, natural gas and natural gas liquids from the Cardium formation at a depth of approximately 2,400 meters. The area has year round access for drilling, seismic and construction projects. Enterra owns infield oil and gas treatment facilities and pipelines in proportion to its well interests. The raw gas is processed at third party processing facilities to remove natural gas liquids. Enterra's average net production for this area for December 2005 was 0.7 mmcf/d of natural gas and 108 bbl/d of oil and natural gas liquids.

McDaniel & Associates has assigned total proved reserves of 760 mmcf of natural gas and 96.4 mbbls of oil and NGLs and total proved plus probable reserves of 981 mmcf of natural gas and 125 mbbls of oil and NGLs to the Lochend property.

Desan, northeast British Columbia
The Desan property is located approximately 75 miles northeast of Fort Nelson, British Columbia. The property is in the center of a well-established gas-producing region commonly referred to as the Greater Sierra. The majority of the drilling, seismic and project construction is carried out during the winter months. Enterra is the operator of the property.

The primary producing formation is the regional Jean Marie at 1,300 meters that is being developed with horizontal well bores. Enterra's average net production for this region for December 2005 was 7.3 mmcf/d of natural gas and 54 bbls/d of oil and natural gas liquids produced from a total of 20 wells. We have 100% working interest in all wells and infrastructure, and operate all wells and compression facilities. McDaniel & Associates has assigned total proved reserves of 15.8 bcf of natural gas and 104 mbbls of NGLs and total proved plus probable reserves of 20.3 bcf of natural gas and 134 mbbls of NGLs to the Desan property.

The company has approximately 37,367 acres of undeveloped land at Desan and nearby similar properties at Kotcho and Peggo Pesh.

Power River/Oyster Ridge, Wyoming and Montana
The Power River/Oyster Ridge property is located in western Wyoming, primarily in the Gillette area. Production is approximately 2.9 mmcf/d net to Enterra for December 2005. We have rights to 89,934 net acres of land, most of

which is undeveloped and prospective for coal bed methane.

Oil and Gas Wells

The following table summarizes the Trust's interest as at December 31, 2005 in wells that are producing and non-producing:

	Producing Oil		Producing Gas		Non Producing		Grand Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	476	313.9	199	98.5	651	370.4	1,326	782.8
US	0	0	65	56.0	146	72.6	211	128.6
Total	476	313.9	264	154.5	797	443.0	1,537	911.4

Land Holdings

The following table summarizes the gross and net acres of unproved properties in which Enterra has an interest at December 31, 2005:

Area	Gross Acres	Net Acres
Canada	241,645	156,859
US	127,090	84,169
Total	368,735	241,028

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

Abandonment and Reclamation Costs

Enterra estimates well abandonment costs on an area-by-area basis. Such costs are included in the McDaniel Report and Sproule Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the McDaniel Report and Sproule Report under the proved reserves category is $19.3 million undiscounted ($9.4 million discounted at 10%), of which a total of $1.8 million is estimated to be incurred in 2006, 2007 and 2008 to abandon 88 wells.

Tax Horizon

Canadian

No cash Canadian income taxes have been paid by the Trust or its Canadian Operating Subsidiaries for the year ended December 31, 2005. Under the current structure, otherwise taxable income of the Canadian Operating Subsidiaries is sheltered through interest expense and other current deductions. Cash is transferred to the Trust by way of interest and redemptions of securities to the Trust. The Trust in turn, allocates all of its taxable income to the Unitholders. No Canadian income taxes are currently expected to be incurred by the Trust or its Canadian Operation Subsidiaries in 2006.

United States

No U.S. income related cash taxes have been paid by the Trust or its U.S. Operating Subsidiaries for the year ended December 31, 2005. The income from Enterra's U.S. operations (reduced by any deductible interest expense on debt held by the Trust or its Canadian subsidiaries) is subject to United States income tax income under U.S. income tax rules and regulations. As a result, Enterra's U.S. operations may incur cash U.S. income taxes in the future. In addition, as funds are repatriated to Canada, withholding taxes that are required by U.S. tax law may become payable.

Costs Incurred

The following table summarizes the expenditures made by Enterra for the year ended December 31, 2005:

		000's
Property acquisition costs: (1)		
Proved properties	$	275,201
Unproved properties		120,484
Exploration costs		-
Development costs		25,895
Total costs incurred	$	421,580

(1) Includes costs related to corporate acquisitions.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that the Trust participated in during the year ended December 31, 2005. In the 2nd Amended and Restated Agreement of Business Principles with JED, the Trust has no interested in dry holes and has a carried interest in producing wells. The carried interest in the producing wells is shown as participated in this table for wells associated with this arrangement.

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	-	-	25	3.85	25	3.85
Natural Gas	-	-	12	2.9	12	2.9
Service	-	-	2	0.93	2	0.93
Dry	-	-	-	-	-	-
Total	-	-	39	7.68	39	7.68

Production Volume by Field

The following table discloses for each important field, and in total, the Trust's production volumes for the financial year ended December 31, 2005 for each product type.

	Crude oil (bbls)	NGLs (bbls)	Natural Gas (Mcf)	BOE
Clair	830,871	32,896	395,930	929,755
Provost	338,560	15,986	465,683	432,160
Princess	226,229	6,557	490,347	314,511
Sylvan Lake	199,280	8,314	167,212	235,462
Desan	-	8,307	1,106,561	192,734
Ferrier/Ricinus	6,445	42,345	800,531	182,212
Other Canadian	258,060	16,301	833,810	413,329
Wyoming	-	-	750,901	125,150
Total	1,859,445	130,705	5,010,974	2,825,313

Production Estimates

The following table discloses for each product type the total volume of production estimated by McDaniel for 2006 in the estimates of future net revenue from proved reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue". The following estimates are applicable under both constant and forecast price scenarios.

Enterra's Average 2006 Production Estimated
Forecast Prices and Costs

Reserve Category	Light and Medium Oil Gross [bbl/d]	Heavy Oil Gross [bbl/d]	Natural Gas Gross [mcf/d]	Natural Gas Liquids Gross [bbl/d]	BOE Gross [BOE/d]
CANADA (McDaniel Report)					
Proved					
Developed Producing	3,367	676	19,507	623	7,917
Developed Non-Producing	3	-	4,269	83	797
Undeveloped	7	-	2,299	72	462
Total Proved	3,377	676	26,075	778	9,176
Probable	209	16	1,829	72	602
Total Proved Plus Probable	3,586	692	27,904	850	9,778
UNITED STATES (Sproule Report)					
Proved					
Developed Producing	-	-	2,727	-	454
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	-	-	2,727	-	454
Probable	-	-	-	-	-
Total Proved Plus Probable	-	-	2,727	-	454
AGGREGATE					
Proved					
Developed Producing	3,367	676	22,234	623	8,371
Developed Non-Producing	3	-	4,269	83	797
Undeveloped	7	-	2,299	72	462
Total Proved	3,377	676	28,802	778	9,630
Probable	209	16	1,829	72	602
Total Proved Plus Probable	3,586	692	30,631	850	10,232

Quarterly Data

The following table discloses, on a quarterly basis for the year ended December 31, 2005, the Trust's share of average daily production volumes, prior to royalties, average prices received, royalties paid, operating expenses incurred and netbacks on a per unit of volume basis.

	Quarter ended 2005			
	Mar 31	Jun 30	Sep 30	Dec 31
Average Daily Production				
Oil (bbl/d)	5,562	4,887	4,858	5,078
NGL (bbl/d)	182	125	435	684
Natural Gas (mcf/d)	6,125	5,867	17,945	24,727
Combined (BOE/d)	6,765	5,990	8,284	9,883
Average Prices Received				
Oil ($/bbl)	51.22	57.17	69.60	56.83
NGL ($/bbl)	40.90	52.69	50.66	57.65
Natural Gas ($/mcf)	6.79	7.09	8.78	8.82
<u>Netback</u>				
Revenues - combined ($/BOE)	49.36	54.69	62.50	55.26
Royalties - combined ($/BOE)	9.89	12.21	13.76	14.21
Operating Expenses - combined ($/BOE)	11.12	13.11	10.10	12.11
Netback Received - combined ($/BOE)	28.35	29.37	38.64	28.95

Additional Information respecting Enterra Energy Trust

The Trust Indenture

The principal undertaking of the Trust is to issue Trust Units and to acquire and hold debt instruments, securities, royalties and other interests. The Operating Subsidiaries of the Trust 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 the Unitholders on a monthly basis. See "Distributions".

Under the terms of the Trust Indenture, the Trust was created for the purposes of:

- acquiring the Series Notes and CT Notes;
- investing in the EECT Units;
- acquiring, holding, transferring and disposing of, investing in and otherwise dealing with assets, securities (whether debt or equity) and other interests (including royalty interests) or properties of whatever nature or kind of, or issued by, EEC, EECT or any other entity in which the Trust owns, directly or indirectly, 50% or more of the outstanding voting securities, including, without limitation, bodies corporate, partnerships or trusts;
- borrowing funds or otherwise obtaining at any time and from time to time or otherwise incurring any indebtedness for any of the purposes set forth in the Trust Indenture;
- disposing of any part of the property of the Trust;
- temporarily holding cash and other short term investments in connection with and for the purposes of the Trust's activities, including paying administration and trust expenses, paying any amounts required in connection with the redemption of Trust Units and making distributions to Unitholders;
- issuing Trust Units, instalment receipts, and other securities (whether debt or equity) of the Trust (including securities convertible into or exchangeable for Trust Units or other securities of the Trust, or warrants, options or other rights to acquire Trust Units or other securities of the Trust), for the purposes of:
  (i) obtaining funds to conduct the activities described above, including raising funds for further acquisitions;
  (ii) repaying of any indebtedness or borrowings of the Trust or any affiliate thereof, including the Series Notes and the CT Notes;
  (iii) establishing and implementing Unitholders rights plans, distribution reinvestment plans, Trust Unit purchase plans, and incentive option and other compensation plans of the Trust, if any;
  (iv) satisfying obligations to deliver securities of the Trust, including Trust Units, pursuant to the terms of securities convertible into or exchangeable for such securities of the Trust, whether or not such convertible or exchangeable securities have been issued by the Trust; and
  (v) making non-cash distributions to Unitholders as contemplated by the Trust Indenture including distributions pursuant to distribution reinvestment plans, if any, established by the Trust;
- guaranteeing the obligations of its affiliates pursuant to any debt for borrowed money or any other obligation incurred by such entity in good faith for the purpose of carrying on its business, and pledging securities and other property owned by the Trust as security for any obligations of the Trust, including obligations under any guarantee;
- repurchasing or redeeming Trust Units or other securities of the Trust, subject to the provisions of the Trust Indenture and applicable law; and
- engaging in all activities incidental or ancillary to any of the foregoing.

Trust Units and Other Securities

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"). In addition, in certain circumstances Unitholders will have the right to instruct the trustees of EECT with respect to the voting of common shares of Enterra held by EECT at meetings of holders of common shares of EEC. See "Meetings of Unitholders" and "Exercise of Voting Rights".

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's assets. 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 do not represent a traditional investment and should not be viewed by investors as "shares" in either Trust or the Trust Subsidiaries. Unitholders do 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 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.

Series Notes
The Series Notes are subordinated to senior indebtedness of the Trust and 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 from the Trust to the Operating Subsidiaries are principal repayments are made on the notes. Interest is be payable for each month during the term on the 15th day of the month following such month. The Series Notes are unsecured debt obligations of Operating Subsidiaries and are subordinated to all senior indebtedness of Enterra.

CT Notes
CT Notes are subordinated, demand participating promissory notes. The CT Notes were issued by EECT to the Trust. Redemptions and returns of capital on shares of EEC held by EECT may be made from time to time and applied as prepayments of the principal amount of the CT Notes. The CT Notes will bear interest at a rate that is re-set from time to time so as to approximate the return on investments held by EECT.

Income Streams
A portion of the cash flows generated by the assets held, directly or indirectly, by the Trust is distributed to Unitholders. The Trustee may, in respect of any period, declare payable to the Unitholders all or any part of the net income of the Trust, less all expenses and liabilities of the Trust due and accrued and which are chargeable to 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 favor of the Trust.

Unitholder Limited Liability
The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust or its obligations or affairs and, in the event that a court determines 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. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely in view of the fact that the sole activity of the Trust is to hold securities, and all of the business operations are carried on by the Operating Subsidiaries.

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 including 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.

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 Board of Directors may determine, including, without limitation, installment or subscription receipts. The Trust Indenture also provides that EEC 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 EEC may determine.

Trustee

Olympia Trust Company is the initial 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 Unitholders. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

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

Delegation of Authority, Administration and Trust Governance

The Board of Directors has generally been delegated the significant management decisions of the Trust. In particular, pursuant to the Trust Indenture, the Trustee has delegated to EEC 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; and (vii) all matters relating to the voting rights on any instruments held by the Trust, other than the EECT.

In addition, pursuant to an administration agreement dated November 25, 2003 between the Trust and EEC (the "Administration Agreement"), EEC has been appointed the administrator of the Trust and is responsible for the administration and management of all general and administrative affairs of the Trust. EEC is not entitled to the payment of a fee for the services provided to the Trust pursuant to the Administration Agreement. At December 31, 2005, Enterra Energy employed 24 office employees and 33 field operations employees for a total of 57 employees.

The Trust, JED and JMG are parties to a 2nd Amended and Restated Agreement of Business Principles Pursuant to the 2nd Amended and Restated Agreement of Business Principles, the Trust appointed JED as the operator or contract operator of the Operating Subsidiaries' development drilling of oil and gas assets and JMG the operator or contract operator of the Operating Subsidiaries' exploration drilling of oil and gas assets. New asset acquisitions by an Operating Subsidiary will be drilled by JED if the prospect has proved production, or by JMG if it does not. The Trust has a first right to purchase assets owned by JED and a right to purchase 80% of interests of JMG when JMG has done sufficient exploratory drilling to prove commercially viable quantities of hydrocarbons, at a value established from an independent reserve report. Both the Trust and JMG will farm out development drilling to JED on the basis that JED will pay 100% of the development costs to earn 70% of working interests. On an individual basis, the terms of the agreement can be varied to meet specific situations with mutual agreement of the affected parties.

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, willful 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.

Special Voting Rights

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

Holders of Special Voting Rights are not entitled to any distributions of any nature whatsoever from the Trust. Each holder shall be entitled to attend at meetings of Unitholders and, subject to the terms of the instrument creating the Special Voting Rights, is entitled to that number of votes equal to the number of votes attached to the Trust Units for which the 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.

Redemption Right

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

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

The aggregate Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that Enterra may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series 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 the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall (herein referred to as "Redemption Notes"). Notwithstanding the foregoing, the distribution of any Series Notes and the issuance of any Redemption Notes shall be conditional upon the receipt of all necessary regulatory approvals and the making of all necessary governmental registrations, declarations and filings, including, without limitation, any required registration of the Series 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 NASDAQ and are not traded or quoted on any other stock exchange or market which Enterra considers, in its sole discretion, provides representative fair market value price for the Trust Units, or (ii) trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by Enterra as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Series Notes and/or Redemption Notes as described above.

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

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by (i) 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 Unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

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

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

Exercise of Voting Rights
The Trustee is prohibited from authorizing or approving:

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

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

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

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

In addition, the Trustee is prohibited from authorizing EECT to vote any shares of Enterra in respect of:

(a) 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;

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

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

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

(e) 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

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

without the prior approval of the 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 Unitholders by ordinary resolution or special resolution, as the case may be.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by Special Resolution of the Unitholders. The Trustee may, without the approval of any of the Unitholders, amend the Trust Indenture for the purpose of:

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

(b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2)