ENTERRA ENERGY TRUST
Form 6-K
August 10, 2004

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

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO RULE 13a-16 OR 15d-16 UNDER THE

SECURITIES ACT OF 1934

For the Month of August 2004

Commission File Number: 000-32115

ENTERRA ENERGY TRUST

(as successor issuer to Enterra Energy Corp.)

(Translation of registrant s name into English)

2600, 500-4th Avenue S.W.
Calgary, Alberta, Canada T2P 2V6

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F_x_ Form 40-F___

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes___ No_x_

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Yes_____ No_x_

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes __ No_x_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b):

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENTERRA ENERGY TRUST
(Registrant)
By: Enterra Energy Corp.
Administrator of the Trust
By: *<u>/s/ Luc Chartrand</u>*
Luc Chartrand
President and Chief Executive Officer
Date: August 4, 2004

MANAGEMENT S DISCUSSION AND ANALYSIS

The following management s discussion and analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements of Enterra Energy Trust ("the Trust") for the period ended March 31, 2004, other financial information included in this quarterly report and with the MD&A and consolidated financial statements contained in the 2003 Annual Report. Additional information relating to the Trust is available on SEDAR at **www.sedar.com**. This MD&A was written as of July 30, 2004. All amounts are stated in Canadian dollars except where otherwise indicated. Natural gas volumes have been converted to a crude oil equivalent using a ratio of 6 mcf to 1 bbl of oil.

Cash flow from operations, expressed before changes in non-cash working capital, is used by the Trust to measure and evaluate operating performance and liquidity. Cash flow from operations does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable with the calculation of similar measures for other companies.

It is management s view, based on its communications with investors during events like conference calls, webcasts or road shows, that cash flow from operations is most relevant to our investors and unitholders, especially since the Trust s conversion to an oil and gas income trust. Cash flow from operations is extremely relevant to investors because it is the starting point for setting the monthly distribution level.

Cash flow from operations is reconciled to GAAP earnings in a table included in the MD&A.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

OVERVIEW

During Q2, 2004, the Trust s production revenue increased 49% over Q2, 2003, with an increase of 22% over the six months ended June 30, 2004 compared to the same period in 2003. Cash flow from operations was $13.5 million for Q2, 2004 or $0.61 on a per unit basis and $23.0 million or $1.06 on a per unit basis for the six months ended June 30, 2004. Production volumes are up 42% and 32% respectively, for the three and six months ended June 30, 2004. The Trust established its initial monthly distribution level at US$0.10 per unit, with an increase to US$0.11 per unit declared on March, April and May production and an increase to US$0.12 per unit declared on June 18, 2004 and payable on July 15, 2004 for June production.

SUMMARIZED FINANCIAL AND OPERATIONAL DATA *(in Thousand s except for volumes and per unit/share amounts)*

	Three Months June 30 2004	Three Months June 30 2003(2)	Change	Six Months June 30 2004(2)	Six Months June 30 2003	Change
Exit production rate (boe per day)	6,927	4,982	+ 39%	6,927	4,982	+ 39 %
Production Revenue	$27,585	$ 18,484	+ 49%	$49,233	$ 40,487	+ 22%
Average production volumes (6 to 1 boe per day)	7,127	5,002	+ 42%	6,702	5,090	+ 32%
Cash flow from operations (1)	$13,532	$ 8,657	+ 56%	$23,029	$21,390	+ 8%
Cash flow from operations per unit (1)	$ 0.61	$ 0.47	+ 30%	$ 1.06	$ 1.16	- 9%
Net earnings	$ 4,647	$ 5,037	- 8%	$ 7,209	$ 9,223	- 22%
Net earnings per unit	$0.21	$ 0.27	- 22%	$ 0.33	$ 0.50	- 34%

Average number of units outstanding *(after giving effect to trust conversion)*	22,019	18,411	+ 20%	21,774	18,388	+ 18%
Average price per bbl of oil (net of hedging loss)	$39.66	$ 39.60	0%	$37.95	$ 43.90	- 14%
Average price per mcf of natural gas	$7.14	$ 7.31	- 2%	$6.87	$ 7.29	- 6%
Operating costs per boe	$7.28	$ 6.90	+ 6%	$7.82	$ 6.67	+ 17%
General and administrative expenses per boe *(cash portion)*	1.20	$ 1.85	- 35%	1.24	$ 1.70	- 27%

(1)

Cash flow from operations is a non-GAAP measure. It is management s view that this information is relevant for investors in order to compare Q2, 2004 with Q2, 2003. Cash flow from operations is reconciled to GAAP earnings in the cash flow section of the MD&A.

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) *The 2003 comparative figures have been restated for the adoption of the change in accounting policy relating to asset retirement obligation.*

PRODUCTION INCOME

Production income increased by 49% in the three months ended June 30, 2004 from $18.5 million in Q2, 2003 to $27.6 million in Q2, 2004. This is primarily due to the inclusion of revenue from the East Alberta properties for the entire Q2, 2004. Production income was $49.2 million for the six months ended June 30, 2004 compared to $40.5 million for the six months ended June 30, 2003, an increase of 22%. This is attributable to oil volumes increasing 42% in this period, with gas volumes unchanged and prices lower in both the three and six months ended June 30, 2004 compared to both periods in 2003.

The Trust exited the second quarter of 2004 at a rate of 6,927 boe/day, consisting of 5,867 bbls/day of oil and 6.360 mcf/day of natural gas, for a mix of 85% oil and 15% natural gas. This represents a 39% increase over the 2003 exit rate of 4,982 boe/day.

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

	Three Months June 30 2004	Three Months June 30 2003	Change	Six Months June 30 2004	Six Months June 30 2003	Change

Crude oil and natural gas liquids	$22,645	$14,388	+ 57 %	$40,503	31,165	+ 30 %
Natural gas	4,940	4,096	+ 21 %	8,730	9,322	- 6 %
Total production income	$27,585	$18,484	+ 49 %	$49,233	$40,487	+ 22 %
Volumes						
Average oil production (in bbls/day)	5,860	3,978	+ 47%	5,538	3,913	+ 42 %
Average gas production (in mcf/day)	7,608	6,144	+ 24%	6,983	7,059	- 1 %
Average total production (in boe/day)	7,127	5,002	+ 42%	6,702	5,090	+ 32 %
Exit oil production (in bbls/day)	5,867	3,690	+ 59 %	5,867	3,690	+ 59%
Exit gas production (in mcf/day)	6,360	7,752	- 18 %	6,360	7,752	- 18 %
Exit total production (in boe/day)	6,927	4,982	+ 39%	6,927	4,982	+ 39 %
Commodity Prices received by Enterra						
Average price received per bbl of oil	$39.66	$ 39.60	0%	$37.95	$ 43.90	- 14%
Average price received per mcf of natural gas	$ 7.14	$ 7.31	- 2%	$ 6.87	$ 7.29	- 6%

PRODUCTION EXPENSES

Production expenses increased by 50% and 55% in the three months and six months ended June 30, 2004, compared to the respective periods in 2003. The increase is due to the higher operating costs associated with the recently acquired East Central Alberta properties. Enterra s existing properties have an average operating cost of $7.75 per boe while the East Central properties have an average operating cost of $13.81 per boe.

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

	Three Months June 30 2004	Three Months June 30 2003	Change	Six Months June 30 2004	Six Months June 30 2003	Change
Production expenses	$4,721	$ 3,139	+ 50%	$9,537	$6,149	+ 55%
As a percentage of production revenue	17%	17%	0%	19%	15%	+ 27%
Production expenses per boe	$7.28	$ 6.90	+ 6%	$7.82	$ 6.67	+ 17%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 22% in Q2, 2004 compared to the Q2, 2003 and by 14% in the six months ended June 30, 2004 compared to the same period in 2003. The increase is the result of the increased production in 2004 offset somewhat by the lower royalty rates on the East Central Alberta properties.

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

	Three Months June 30 2004	Three Months June 30 2003	Change	Six Months June 30 2004	Six Months June 30 2003	Change
Royalties, net of Alberta Royalty Tax Credit	$6,455	$ 5,306	+ 22%	$11,645	$10,241	+ 14 %
As a percentage of production revenue	23%	29%	- 21%	24%	25%	- 4%
Royalties per boe	$9.95	$11.66	- 15%	$9.55	$11.12	- 14%

GENERAL AND ADMINISTRATIVE EXPENSES

The cash portion of general and administrative expenses is 3% of production revenue for both the three months and six months ended June 30, 2004. This represents a decrease of 8% in Q2, 2004 compared to Q2, 2003 and a decrease of 3% in the six months ended June 30, 2004 compared to the same period in 2003. The non-cash portion of general and administrative expenses in 2004 relate to the value assigned to 920,000 options granted to employees and directors.

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

	Three Months June 30 2004	Three Months June 30 2003	Change	Six Months June 30 2004	Six Months June 30 2003	Change
General and administrative expenses cash portion	$779	$ 842	- 8%	$1,512	$1,565	- 3%
General and administrative expenses non cash portion	$ 240	$ -	+ 100%	$ 441	$ -	+ 100 %
As a percentage of production revenue (cash portion)	3%	5%	- 40%	3%	4%	- 25%
General and administrative expenses per boe (cash portion)	$1.20	$ 1.85	- 35%	$1.24	$ 1.70	- 27%

INTEREST EXPENSE

Interest expense increased by 24% in Q2, 2004 compared to Q2, 2003 and 27% in the six months ended June 30, 2004 compared to the same period in 2003. The 2004 increase is due to the higher average outstanding loan balances during the same periods in 2003.

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

	Three Months	Three Months	Change	Six Months	Six Months	Change

	June 30 2004	June 30 2003		June 30 2004	June 30 2003	
Long-term debt, including bank debt at end of period	$32,587	$24,072	+ 35 %	$32,587	$24,072	+ 35%
Interest expense	$ 580	$ 466	+ 24%	$ 1,221	$ 960	+ 27%
As a percentage of production revenue	2%	3%	- 33%	2%	2%	0 %
Interest expense per boe	$ 0.89	$ 1.02	- 13%	$ 1.00	$ 1.04	- 4%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 45% in Q2, 2004 compared to Q2, 2003, primarily due to the higher depletable base with the addition of the East Central Alberta properties.

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

	Three Months June 30 2004	Three Months June 30 2003 (restated)	Change	Six Months June 30 2004	Six Months June 30 2003 (restated)	Change
Depletion and depreciation expense	$8,561	$5,919	+ 45%	$16,364	$11,330	+ 44 %
As a percentage of production revenue	31%	32%	- 3%	33%	28%	+ 18%
Depletion and depreciation expense per boe	$13.20	$13.00	+ 1%	$13.42	$ 12.30	+ 9%

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INCOME AND CAPITAL TAXES

The Trust recorded an income tax recovery of $1.0 million in the six months ended June 30, 2004 compared with a provision of $0.8 million in the same period in 2003. The decrease in income tax is primarily due to larger interest payments from Enterra to the Trust, which are deductible for Enterra (taxable to the unitholder by way of distributions) in calculating future taxes, together with a decrease in a substantively enacted Alberta income tax rate by 1% and the tax impact of adopting the new accounting policies.

Income tax expense *(in Thousand s except for percentages)*

	Three Months June 30 2004	Three Months June 30 2003 (restated)	Change	Six Months June 30 2004	Six Months June 30 2003 (restated)	Change
Income tax expense (recovery)	$1,305	$(2,230)	+ 158%	$(952)	$776	- 223%
Combined federal and provincial income tax rate	39.12%	42.12%	- 7%	39.12%	42.12%	- 7%

EARNINGS

The Trust s net earnings for the Q2, 2004 are 8% lower than the Q2, 2003. The 49% higher revenue as a result of higher oil volumes was more than offset by:

- higher depletion expense as a result of the increased production and the higher depletable base.
- higher operating costs related to the East Central Alberta properties.
- higher royalties resulting from the increased production.
- higher realized hedging losses.
- a reduction in the future income tax recovery of $1.3 million.

Earnings for the six months ended June 30, 2004 were $7.2 million compared to $9.2 million in 2003, or a decrease of 22%. Production income increased by 22% in the six month period ended June 30, 2004 compared to June 30, 2003 with the increases in operating costs, royalties, depletion expense, realized hedging losses and interest expense more than offsetting this six month increase in income.

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

	Three Months	Three Months	Change	Six Months	Six Months	Change

	June 30 2004	June 30 2003 (restated)		June 30 2004	June 30 2003 (restated)	
Net earnings	$4,647	$5,037	- 8%	$7,209	$9,223	- 22%
Net earnings as a percentage of revenue	17%	27%	- 37%	15%	23%	- 35%
Net earnings on a per boe basis	$7.16	$11.06	- 35%	$5.91	$10.01	- 41%
Per unit information						
Net earnings per unit	$0.21	$0.27	- 22%	$0.33	$0.50	- 34%
Average number of units outstanding	22,019	18,411	+ 20%	21,774	18,388	+ 18%

CASH FLOW FROM OPERATIONS

Cash flow from operations of $13.5 million increased by $4.9 million or 56% in Q2, 2004 compared to Q2, 2003. This is attributable to higher oil production volumes partially offset by higher operating costs on the newly acquired properties as well as higher royalties, realized hedging losses and interest expense.

The changes on a per unit basis showed similar results with an increase to $0.61 per unit from $0.47 per unit or 47% in Q2 of 2004 compared to Q2 of 2003. The cash flow per unit for the six months ended June 30, 2004 was $1.06 per unit compared to $1.16 per unit for the same period in 2003.

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

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

	Three Months June 30 2004	Three Months June 30 2003 (restated)	Change	Six Months June 30 2004	Six Months June 30 2003 (restated)	Change

Net earnings	$4,647	$5,037	- 8%	$7,209	$9,223	- 22%
Add back depletion and depreciation	8,561	5,919	+ 45%	16,363	11,330	+44%
Add back (deduct) amortization of deferred financing charges	18	40	- 55%	28	280	- 90%
Add back (deduct) future income taxes	1,275	(2,260)	+156%	(1,012)	716	-241%
Deduct amortization of deferred gain	-	(79)	+100%	-	(159)	+100%
Add back amortization of deferred derivative loss	479	-	+100%	958	-	+100%
Deduct reduction in financial derivative liability	(1,688)			(958)		
Add back non-cash expense related to value of options	240	-	+100%	441	-	+100%
Cash flow from operations	13,532	8,657	+ 56%	23,029	21,390	+ 8%
Cash flow from operations as a percentage of revenue	49%	47%	+ 4%	47%	53%	- 11%
Cash flow from operations on a per boe basis						
Per unit information						
Cash flow from operations per unit	$0.61	$0.47	+ 30%	$1.06	$1.16	-9%
Average number	22,019	18,411	+ 20%	21,774	18,388	+18%

of units outstanding

CAPITAL EXPENDITURES

Capital expenditures for the six months ended June 30, 2004 were $23.9 million compared to $15.4 million in the six months ended June 30, 2003. Proceeds on disposal were $0.2 million and $0.8 million for the three and six months ended June 30, 2004 respectively compared to $0.6 million and $15.6 million for three and six month periods ending June 30, 2003.

The 2004 capital expenditures were almost exclusively related to the acquisition of the East Central Alberta properties ($19.8 million), which was completed on January 30, 2004. There were minimal disposals in 2004 compared to disposals of $15.6 million for the six months ended June 30, 2003.

CASH DISTRIBUTIONS

The Trust paid distributions of US$0.10 per unit for the month of December 2003 and for the first two months of 2004. The Trust paid distributions of US$0.11 per unit for the months of March, April and May of 2004. The distribution for the month of June 2004 was raised to US$0.12 per unit. Cash distributions are paid on the 15th of the following month (e.g. the June distribution is paid on July 15).

Total distributions paid out during the three and six months ended June 30, 2004 were $9.6 million and $17.4 million respectively, representing 71% and 76% of Enterra s cash flow for these periods.

LIQUIDITY AND CAPITAL RESOURCES

The Trust s bank debt at June 30, 2004 was $28.9 million (December 31, 2003 - $34 million). In both periods the funds were used to acquire capital assets and support ongoing operations. At June 30, 2004 the Trust s bank facility consisted of a line of credit of $32.9 million (December 31, 2003 - $34.7 million). Interest on amounts drawn is based on the bank s prime rate plus 0.25%.

On January 16, 2004 the Trust entered into a financing agreement whereby the Trust would issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$ 16,500,000. The financing closed and payment was received on June 29, 2004 upon registration of the units. These funds will be applied towards the financing for the East Central Alberta property acquisition described below.

On January 30, 2004 the Trust closed an acquisition of properties in East Central Alberta for $19.8 million.

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

Capital expenditures should be approximately $5-$10 million in 2004 because Enterra, as an income trust, will be distributing approximately 80% of its cash flow through its monthly distributions. The Trust s strategy for growth in 2004 will be focused on property acquisitions which will be funded with a combination of additional debt and equity.

Enterra has approximately $74.0 million in tax pools available at June 30, 2004. (June 30, 2003 - $44.9 million)

The Trust has a number of forward contracts in place during the year in order to minimize the volatility in crude oil pricing. Below is a summary of the Trust s hedging operations in 2004:

Hedging summary

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

At June 30, 2004, the Trust had a total of 23,178,931 Trust units (December 31, 2003 18,955,960) and 501,159 Exchangeable shares (December 31, 2003 1,995,596) outstanding. No additional units were issued as of July 30, 2004.

CRITICAL ACCOUNTING POLICIES

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

· Capitalized costs under the full cost method are generally depleted and depreciated using the unit-of-production method, based on estimated proved oil and gas reserves as determined by independent engineers. In addition, capital costs are also restricted from exceeding the ceiling test under Accounting Guideline No. 16 as more fully described below. Should this comparison indicate an excess carrying value, a write-down would be recorded. To economically evaluate the Trust s proved oil and natural gas reserves, these independent engineers must necessarily make a number of assumptions, estimates and judgments that they believe to be reasonable based upon their expertise and professional and CICA and SEC guidelines. Were the independent engineers to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected. For example, the Trust would have lower net earnings (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in lower reserve estimates, since our depletion and depreciation rate would then be higher and it might also result in a write-down under the ceiling test. Similarly, the Trust would have higher net earnings (or lower net losses) in the event the revised assumptions, estimates and judgments resulted in higher reserve estimates.

· The Trust s management also periodically assesses the carrying values of unproved properties to ascertain whether any impairment in value has occurred. This assessment typically includes a determination of the anticipated future net cash flows based upon reserve potential and independent appraisal where warranted. Impairment is recorded if this assessment indicates the future potential net cash flows are less than the capitalized costs. Were the Trust s management to use differing assumptions, estimates and judgments, then the Trust s consolidated financial condition and results of operations would be affected. For example, the Trust would have lower net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in increased impairment expense.

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

· In January 1, 2004, the Trust adopted CICA Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments. Effective January 1, 2004, the Trust has recorded the fair value of financial instruments as a deferred financial loss of $958,359 and a deferred financial liability of $958,359 on the balance sheet. At June 30, 2004, the deferred financial loss was amortized to a balance of nil through revenues and the deferred liability was decreased to zero.

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

As a result of the adoption of this policy, the Trust has recorded a charge to retained earnings of $646,031 as at January 1, 2004 to reflect the accumulated stock option expense awards made under the plan subsequent to January 1, 2002. The estimated fair value of the options issued in 2003 and 2002 has been determined using a Black-Scholes option-pricing model.

- Effective January 1, 2004, the Trust adopted Accounting Guideline 16, "Oil and Gas Accounting Full Cost" which replaces AcG-5 Full Cost Accounting in the Oil and Gas industry. AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There is no write down of the Trust s property, plant and equipment under either the old or the new method as of January 1, 2004 or June 30, 2004.

ENTERRA ENERGY TRUST

Consolidated Balance Sheets

(Expressed in Canadian dollars)

(Unaudited)

	June 30	December 31
	2004	2003
		(as restated)
		Note 1

Assets		
Current assets		
Cash	$ 7,714,872	$ 65,643
Accounts receivable	10,464,264	8,742,690
Deposit on land purchase	-	2,015,000
Prepaid expenses and deposits	364,216	461,727
	18,543,352	11,285,060
Capital assets	113,161,598	105,253,166
Deferred financing charges	283,942	123,208
	$131,988,892	$116,661,434
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 5,913,548	$ 12,208,390
Distributions payable to unitholders	3,677,662	2,451,402
Income taxes payable	80,000	120,000
Bank indebtedness (note 2)	28,865,000	33,959,733
Current portion of long-term debt	731,488	782,930
	39,267,698	49,522,455
Asset retirement obligation (note 1(b))	3,328,388	2,188,052
Future income tax liability (note 3)	12,924,127	13,936,327
Long-term debt	2,991,461	3,385,618
	58,511,674	69,032,452
Unitholders Equity		
Unitholders capital (note 4(a))	72,911,534	32,838,163

Exchangeable shares (note 4(b))	868,178	3,457,050
Contributed surplus (note 1(d))	441,050	-
Accumulated earnings	20,347,767	13,785,171
Accumulated distributions	(21,091,311)	(2,451,402)
	73,477,218	47,628,982
Forward contracts (note 5)	$131,988,892	$116,661,434

Approved on behalf of the Board:

Reg Greenslade Director Bill Sliney Director

See accompanying notes to consolidated financial statements

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ENTERRA ENERGY TRUST

Consolidated Statements of Earnings and Accumulated Earnings

Three and Six Months Ended June 30

(Expressed in Canadian dollars)

(Unaudited)

	Three Months June 30 2004	Three Months June 30 2003 (as restated)	Six Months June 30 2004	Six Months June 30 2003 (as restated)
Revenue				
Oil and gas	$27,585,084	$18,484,488	$49,233,300	$40,486,859
Royalties, net of ARTC	(6,455,15)	(5,305,946)	(11,644,744)	(10,240,838)
	21,129,927	13,178,542	37,588,556	30,246,021

Expenses				
Production	4,721,341	3,139,202	9,536,804	6,148,531
General and administrative	1,018,937	842,206	1,952,871	1,564,781
Depletion, depreciation and accretion	8,560,595	5,919,143	16,363,595	11,329,811
Amortization of deferred financing charges	18,290	4,800	27,812	244,535
Interest	580,223	466,174	1,221,078	959,895
Financial derivative loss (note 1(c))	278,863	-	2,229,969	-
	15,178,249	10,371,525	31,332,129	20,247,553
Earnings before income taxes	5,951,678	2,807,017	6,256,427	9,998,468
Income taxes:				
Current	30,000	30,000	60,000	60,000
Future (recovery) (note 3)	1,274,727	(2,259,839)	(1,012,200)	715,936
	1,304,727	(2,229,839)	(952,200)	775,936
Net earnings	4,646,951	5,036,856	7,208,627	9,222,532
Accumulated earnings, beginning of period	15,700,816	12,869,838	13,937,025	8,933,223
Changes in accounting policy related to:				
Asset retirement obligation (note 1(b))	-	-	(151,854)	(249,061)
Unit based compensation (note 1(d))	-	-	(646,031)	-
Accumulated earnings as restated, beginning of period	15,700,816	12,869,838	13,139,140	8,684,162
Accumulated earnings, end of period	$20,347,767	$17,906,694	$20,347,767	$17,906,694
Earnings per unit/share:				
Basic	$0.21	$ 0.27	$0.33	$ 0.50
Diluted	$0.21	$ 0.25	$0.33	$ 0.47

See accompanying notes to consolidated financial statements

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ENTERRA ENERGY TRUST

Consolidated Statements of Cash Flows

Three and Six Months Ended June 30

(Expressed in Canadian dollars)

(Unaudited)

	Three Months June 30 2004	Three Months June 30 2003 (as restated)	Six Months June 30 2004	Six Months June 30 2003 (as restated)
Cash provided by (used in):				
Operations				
Net earnings	$4,646,951	$5,036,856	$7,208,627	$9,222,532
Add non-cash items:				
Depletion, depreciation and accretion	8,560,595	5,919,143	16,363,595	11,329,811
Future income taxes	1,274,727	(2,259,839)	(1,012,200)	715,936
Amortization of deferred gain	-	(79,172)	-	(158,989)
Amortization of deferred financing charges	18,290	40,491	27,812	280,226
Amortization of deferred financial derivative loss	479,179	-	958,359	-
Reduction in financial derivative liability	(1,688,149)	-	(958,359)	-
Unit based compensation (note 1(d))	240,333	-	441,050	-
	13,531,926	8,657,479	23,028,884	21,389,516

Net change in non-cash working capital items:				
Accounts receivable	(105,136)	10,103,566	(1,721,574)	(2,491,044)
Prepaid expenses and deposits	52,998	(14,705)	97,511	206,496
Accounts payable and accrued liabilities	1,458,462	(5,936,493)	(6,294,842)	(14,255,640)
Future abandonment and site restoration costs	-	(269)	-	(2,669)
Income taxes payable	(70,000)	26,000	(40,000)	50,147
	14,868,250	12,835,578	15,069,979	4,896,806
Financing				
Bank indebtedness	(2,400,000)	(5,195,000)	(5,094,733)	(4,889,140)
Long-term debt	(254,777)	(198,664)	(445,599)	(397,304)
Deferred financing charges	(178,446)	(3,144)	(188,546)	(77,780)
Issue of units/shares, net of issue costs	21,965,059	237,552	36,838,468	265,552
Cash distributions	(9,585,362)	-	(17,413,649)	-
Advance from joint venture partner	(17,001,992)	-	-	-
Redemption of preferred shares	-	(23,679)	-	(61,005)
	(7,455,518)	(5,182,935)	13,695,941	(5,159,677)
Investing				
Capital assets additions	-	(8,265,711)	(23,908,311)	(15,443,770)
Proceeds on disposal of property and equipment	291,764	643,792	776,620	15,630,356
Deposit on land purchase	-	-	2,015,000	-
	291,764	(7,621,919)	(21,116,691)	186,586
Net increase (decrease) in cash	7,704,496	30,724	7,649,229	(76,285)
Cash, beginning of period	10,376	1,008	65,643	108,017
Cash, end of period	$7,714,872	$31,732	$7,714,872	$31,732

During the three and six months ended June 30, 2004, the Trust paid respectively $466,447 and $1,018,376 (2003 - $367,306 and $758,575) of interest on long-term debt and taxes of $100,000 and $100,000 respectively (2003 - $nil in both periods). During the three and six months ended June 30, 2004, the Trust capitalized general and administrative expenses respectively of $295,900 and $602,295 (2003 - $437,800 and $943,400).

See accompanying notes to consolidated financial statements

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Enterra energy TRUST

Notes to Consolidated Financial Statements

For the Three and Six Months Ended June 30, 2004 and 2003

(Unaudited)

The interim consolidated financial statements of Enterra Energy Trust (the "Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods used in preparing the consolidated financial statements for the fiscal year ended December 31, 2003, except as described in note 1, and should be read in conjunction with those consolidated financial statements. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust s annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements have been condensed or omitted. Certain comparative amounts have been reclassified to conform to the current presentation.

1. Changes in Accounting Policies

(a) Full Cost Accounting

Effective January 1, 2004, the Trust adopted Accounting Guideline 16, "Oil and Gas Accounting Full Cost" which replaces AcG-5 Full Cost Accounting in the Oil and Gas industry. AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline modifies the ceiling test to be performed in two stages. The first stage requires the carrying value to be tested for recoverability using undiscounted future cash flows from proved reserves using forward indexed prices. If the carrying value is not recoverable, the second stage, which is based on the calculation of discounted future cash flows from proved plus probable reserves, will determine the impairment to the fair value of the asset. There is no write down of the Trust s property, plant and equipment under either the old or the new method as of January 1, 2004 or June 30, 2004. The base average price forecasts used by the individual consultants evaluating the existing reserves and purchased reserves are adjusted for quality, transportation and heat content and are outlined in the following table.

	2004	2005	2006	2007	2008	Thereafter
WTI ($US/bbl)	29.00	26.50	25.50	25.00	25.00	25.50-33.60
WTI ($US/bbl)	29.00	25.50	24.25	24.00	23.25	23.25-21.50
AECO Spot Price ($Cdn/mcf)	5.50	5.19	4.87	4.68	4.53	4.57-5.95
	5.85	5.15	5.00	5.00	5.00	5.00*

AECO Spot Price ($Cdn/mcf)

* increasing 1.5%/year after 2014.

(b) Asset Retirement Obligations

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

At June 30, 2004, the Trust estimated the asset retirement obligation to be $3.3 million (December, 2003 - $2.2 million), based on a total future liability of $12.8 (December 31, 2003 - $4.2 million). These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 30 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a weighted average credit-adjusted risk-free interest rate of 5.9%.

The following table summarizes the changes resulting from this restatement.

	Balance as Previously Reported	Adjustments	Balance as Restated
Balance Sheet as at December 31, 2003			
Capital assets	$104,821,285	431,881	$105,253,166
Asset retirement obligation	$ 1,529,244	658,808	$ 2,188,052
Accumulated earnings	$ 13,937,025	(151,854)	$ 13,785,171
Future income tax liability	$ 14,011,400	(75,073)	$ 13,936,327

	Balance as Previously Reported	Adjustments	Balance as Restated
Statement of Earnings for Six months ended June 30, 2003			
Depletion, depletion and accretion	$11,437,000	(107,189)	$11,329,811
Future income tax expense	$ 679,899	36,037	$ 715,936

Net Earnings	$ 9,151,380	71,152	$ 9,222,532

The following table reconciles the asset retirement obligation associated with the retirement of oil and gas properties.

Asset Retirement Obligation at January 1, 2003 (as restated)	**$3,090,389**
Obligation incurred	**744,422**
Abandonment expenditures	**(5,414)**
Property disposition	**(1,753,446)**
Accretion expense	**112,101**
Asset Retirement Obligation at December 31, 2003 (as restated)	**$2,188,052**
Obligation incurred	**1,230,558**
Abandonment expenditures	**-**
Property disposition	**(120,817)**
Accretion expense	**30,595**
Asset Retirement Obligation at June 30, 2004	**$3,328,388**

(c)

Financial Instruments

On January 1, 2004, the Trust adopted CICA Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied and addresses the identification, designation, documentation and effectiveness of hedging transactions. Where hedge accounting does not apply, any changes in the mark to market values of the forward contracts relating to a financial period can either reduce or increase net earnings and net earnings per unit for that period. The Trust has elected not to apply hedge accounting to any of its financial instruments. Effective January 1, 2004, the Trust has recorded the fair value of financial instruments as a deferred financial loss of $958,359 and a deferred financial liability of $958,359 on the balance sheet. At June 30, 2004, the remaining deferred financial loss of $479,180 was amortized through revenues and the deferred liability was decreased to zero, as the Trust no longer hedges with financial instruments.

The following table reflects the changes in the financial derivative liability and deferred financial derivative loss accounts during the period.

Financial Derivative Liability at January 1, 2004	**$ 958,359**

Financial instruments settled	**(3,188,328)**
Mark to market realized loss	**2,229,969**
Financial Derivative Liability at June 30, 2004	**$ nil**

Deferred Financial Derivative Loss at January 1, 2004	**$958,359**
Amortization of deferred financial loss	**(958,359)**
Deferred Financial Derivative Loss at June 30, 2004	**$ nil**

(d) Unit-based Compensation

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

As a result of the adoption of this policy, the Trust has recorded a charge to accumulated earnings of $646,031 as at January 1, 2004 to reflect the accumulated unit option expense awards made under the plan subsequent to January 1, 2002. The estimated fair value of the options issued in 2003 and 2002 has been determined using a Black-Scholes option pricing model.

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

	2003	2003
	Three Months	Six Months
	June 30	June 30
	(as restated)	(as restated)
Net earnings (in 000 s)		
As reported	$ 5,037	$ 9,223
Less fair value of stock options to employees	(73)	(144)
Pro Forma	$ 4,964	$ 9,079

Earnings per common share ($/share)		
Basic as Reported	$0.27	$0.50
Pro Forma	$0.27	$0.49
Diluted as Reported	$0.25	$0.47
Pro Forma	$0.25	$0.46

In 2004, 920,000 options were issued to employees at a fair value of $3.47 per unit as determined by the Black-Scholes model resulting in compensation expense for the three and six months ended June 30, 2004 of $200,717 and $441,050 respectively with a corresponding credit to contributed surplus. Assumptions used in the 2004 Black-Scholes model were a risk free interest rate of 3.8%, a distribution yield of 9%, a 5 year life and volatility of 21%. Assumptions in the 2003 Black-Scholes model applied before the conversion to a Trust were a risk free interest rate of 5.0%, a distribution yield of 0%, a 5 year life and volatility of 50%.

2. Bank indebtedness

Bank indebtedness represents the outstanding balance under a line of credit of $32,900,000 (2003 - $26,700,000). Drawings bear interest at 0.25% above the bank s prime lending rate. Security is provided by a first charge over all of the Trust s assets. The balance is repayable on demand. While the loan is due on demand, the Trust is not subject to scheduled repayments. The amount available under the line was increased in January 2004 to $39,650,000 and decreased by $1,350,000 per month until May 31, 2004, to a balance of $32,900 000.

3. Future income tax liability

The decrease in the future income tax liability is primarily due to larger interest payments from Enterra Energy Corp. ("Enterra") to the Trust, which are deductible for Enterra (taxable to the unitholder by way of distributions) in calculating future taxes, together with a decrease in a substantively enacted Alberta income tax rate by 1% in the first quarter and the tax impact of adopting the new accounting policies as set out in note 1.

4. Unitholders Equity

(a) Issued Trust Units:

	Number of Units	**Amount**
Balance at December 31, 2003	18,955,960	$ 32,838,163
Issued for exchangeable shares	1,523,571	2,588,872

Issued in private placement, net of issue costs	2,699,400	36,838,468
Adoption of unit-based compensation (note 1(d))	-	646,031
Balance at June 30, 2004	23,178,931	$ 72,911,534

(b) Issued Exchangeable Shares:

	Number of Units	**Amount**
Balance at December 31, 2003	1,995,596	$3,457,050
Exchanged for Trust Units	(1,494,437)	(2,588,872)
Balance at June 30, 2004	501,159	$ 868,178

The exchangeable shares are exchangeable into Trust units at an exchange ratio which is adjusted each time the Trust makes a distribution to its unitholders. The exchange ratio was 1:1 on December 31, 2003 and is 1:1.05104 on June 30, 2004.

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(c) Options:

	Number of Options	**Weighted-average exercise price**
Balance at December 31, 2003	-	$ -
Options granted	920,000	$14.00
Balance at June 30, 2004	920,000	$14.00

Reconciliation of earnings per unit/share calculation:

The weighted average number of units outstanding for the three and six months ended June 30, 2004, was 22,019,088 and 21,773,619 respectively.

Three Months Ended June 30, 2003

	Net Earnings (as restated)	**Weighted Average Shares Outstanding**	**Per Share**
Basic	$5,036,856	18,411,466	$0.27
Options assumed exercised		2,016,180	

Shares assumed purchased		(594,064)	
Diluted	$5,036,856	19,833,582	$0.25

Six Months Ended June 30, 2003

	Net Earnings (as restated)	Weighted Average Shares Outstanding	Per Share
Basic	$9,222,532	18,388,178	$0.50
Options assumed exercised		2,013,304	
Shares assumed purchased		(646,768)	
Diluted	$9,222,532	19,754,714	$0.47

5. Forward contract

On January 23, 2004, the Trust entered into contracts to deliver 1,000 barrels of oil per day from July 1, 2004 to December 31, 2004 at Cdn$40.50.

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Form 52-109FT2 Certification of Interim Filings during Transition Period

I***, Luc Chartrand, President & CEO of Enterra Energy Trust***, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*) of Enterra Energy Trust, (the issuer) for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: August 4, 2004

/s/Luc Chartrand

Luc Chartrand, President & CEO

Form 52-109FT2 Certification of Interim Filings during Transition Period

I, ***Lynn Wiebe, CFO of Enterra Energy Trust***, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers Annual and Interim Filings*) of Enterra Energy Trust (the issuer) for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: August 4, 2004

/s/ Lynn Wiebe

Lynn Wiebe, CFO