



ENERGY TRUST
Enterra

Q3

2006 QUARTERLY REPORT TO
THE UNITHOLDERS
Nine months ended September 30, 2006

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Stock exchange listings

NYSE (symbol: ENT)
TSX (symbol: ENT.UN)

ENTERRA ENERGY TRUST

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of Enterra Energy Trust ("the Trust") for the nine-month period ended September 30, 2006. This MD&A should be read in conjunction with the MD&A and the consolidated financial statements, together with the accompanying notes, of the Trust for the year ended December 31, 2005, as well as the unaudited interim consolidated financial statements, together with the accompanying notes, of the Trust for the nine-month period ended September 30, 2006. All amounts are stated in Canadian dollars and are prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") except where otherwise indicated. This MD&A was written as of November 9, 2006.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This MD&A includes forward-looking statements. All statements other than statements of historical facts contained in this MD&A, including statements regarding the Trust's 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 the Trust, are intended to identify forward-looking statements. The Trust has based these forward-looking statements largely on the Trust's current expectations and projections about future events and financial trends that the Trust believes may affect its financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions as described in the Trust's Annual Information Report, Annual Report and elsewhere in this MD&A.

Other sections of this MD&A may include additional factors that could adversely affect the Trust's business and financial performance. Moreover, the Trust 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, nor can the Trust assess the impact of all factors on the Trust's 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 Trust undertakes no obligation, except as required by securities law, to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. The Trust cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although the Trust believes that the expectations reflected in the forward-looking statements are reasonable, the Trust cannot guarantee future results, levels of activity, performance or achievements.

SPECIAL NOTE REGARDING NON-GAAP TERMS

This document contains the term "funds from operations", which is a non-GAAP term. The Trust uses this measure to help evaluate its performance. The Trust considers it a key measure for the ability of the Trust to repay debt, make distributions to Unitholders and to fund future growth through capital investment. The term should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. Funds from operations, as determined by the Trust may not be comparable to that reported by other companies. The reconciliation for funds from operations to cash provided by operating activities can be found in the non-GAAP financial measures section of this MD&A.

CERTAIN FINANCIAL REPORTING MEASURES

Natural gas volumes recorded in thousand cubic feet (“mcf”) are converted to barrels of oil equivalent (“boe”) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (“bbl”). Boe’s 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.

OVERVIEW AND STRATEGY

The Trust operates as an oil and natural gas income trust. The Trust pays monthly cash distributions in U.S. dollars based on a current target payout ratio of 60% to 70% of funds from operations on the 15th day of each month to Unitholders of record on the immediately preceding distribution record date. The goal is to maintain and enhance oil and natural gas reserves to provide sustainable and predictable cash distributions to Unitholders. The Trust’s business strategy provides three avenues to achieve its goal:

1. Organic growth by investing funds in lower-risk projects within existing core areas of operation;
2. Accretive acquisitions of oil and natural gas assets that create new core areas with organic growth, strategic partnership potential or consolidate an existing core area; and
3. Strategic partnerships to gain exposure to opportunities otherwise not available to the Trust and to secure the potential to acquire the partner’s interest in the future.

Acquisitions are financed with cash flow, equity and debt, the optimal mix being one that provides for the strongest balance sheet. The Trust’s ability to replace and grow reserves using these strategies is a key success factor in its business outcomes.

During the first six months of 2006, the Trust acquired oil and natural gas producing assets located in Oklahoma (“Oklahoma Assets”). The acquisition was completed through four closings. The first closing occurred on January 18, 2006 and represented approximately 1,300 boe/day of production capacity. The second closing occurred on March 21, 2006 and represented approximately 3,700 boe/day of production capacity. The final two closings occurred on April 4, 2006 and April 18, 2006 and represented approximately 1,300 boe/day of production capacity.

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

OVERALL PERFORMANCE

Increased natural gas sales volumes, arising from the acquisition of High Point Resources Ltd. effective August 17, 2005 and the inclusion of the acquisition of the Oklahoma Assets as of their respective closing dates during Q1 and Q2 2006, positively affected the Trust's financial results.

The Trust exited the third quarter of 2006 with sales volumes of approximately 12,580 boe/day. The Trust realized an average total production of 13,070 boe/day for Q3 2006 compared to 8,284 boe/day in Q3 of 2005.

The positive impact of the increase in production from the acquisitions was somewhat offset by lower oil and natural gas prices. The Trust increased funds from operations by 6% to \$25.3 million compared to \$23.9 million in Q3 2005. Cash provided by operating activities was down by 30% to \$11.7 million in Q3 2006 compared to \$16.6 million in Q3 2005. As a result of the mark to market gains on the Trust's financial instruments, the Trust realized net earnings of \$3.0 million for Q3 2006 compared to net earnings of \$7.1 million in Q3 2005. On a per unit basis, the Trust realized net earnings of \$0.07/unit compared to \$0.23/unit in Q3 2005.

A total of \$21.1 million was paid to Unitholders through distributions in Q3 2006 compared to \$16.9 million in Q3 2005.

SUMMARIZED FINANCIAL AND OPERATIONAL DATA *(in thousands except for volumes and per unit amounts)*

	Three months ended September 30,			Nine months ended September 30,		
	2006	2005		2006	2005	
			<i>Change</i>			<i>Change</i>
Oil and natural gas revenues	\$64,045	\$47,638	34%	\$178,296	\$107,495	66%
Average sales (boe/day)	13,070	8,284	58%	12,502	7,019	78%
Exit sales rate (boe/day)	12,580	9,887	27%	12,580	9,887	27%
Cash provided by operating activities	\$11,692	\$16,622	(30%)	\$38,322	\$47,545	(19%)
Funds from operations ⁽¹⁾	\$25,281	\$23,940	6%	\$76,559	\$51,026	50%
Net earnings	\$3,000	\$7,089	(58%)	\$4,951	\$13,907	(64%)
Net earnings per trust unit - basic	\$0.07	\$0.23	(70%)	\$0.12	\$0.50	(76%)
Weighted average number of trust units outstanding - basic	44,816	31,052	44%	42,365	27,591	54%
Average price per barrel of oil	\$66.74	\$69.60	(4%)	\$64.17	\$59.07	9%
Average price per mcf of natural gas	\$7.47	\$8.78	(15%)	\$7.40	\$8.02	(8%)
Production expenses per boe	\$11.43	\$10.10	13%	\$9.61	\$11.28	(15%)

⁽¹⁾ Funds from operations is a non-GAAP financial measure. See non-GAAP financial measures section of the MD&A for a reconciliation of this measure.

RESULTS OF OPERATIONS

Production

The Trust's average production increased by 58% to 13,070 boe/day from 8,284 boe/day in Q3 2005. This increase is the result of the acquisition of High Point in August 2005 and the subsequent development of these properties, in addition to the closings of the Oklahoma Asset acquisitions throughout Q1 and Q2 2006. Fourteen wells were drilled on Trust lands in Canada in Q1 2006, and eight of these, along with wells drilled in Q4 2005, were brought on production during the first quarter through a combination of existing and newly constructed facilities. During Q2 2006 the Trust participated in 2 wells on its land in Canada. Five wells were drilled on Trust lands in the U.S. during Q2. During Q3, the Trust participated in 7 wells on its land in Canada. Five wells were drilled on Trust lands in the U.S. during Q3. The Trust's average production during Q3 2006 consisted of 5,221 bbls/day of oil and natural gas liquids ("NGL") and 47,094 mcf/day of natural gas, resulting in a mix of 40% oil and NGL and 60% natural gas. As at September 30, 2006, the Trust had an exit rate of 12,580 boe/day. The relatively lower exit rate at September 30, 2006 was due to temporary reductions in volume associated with large-scale well workover and maintenance on the Oklahoma Assets.

Production (in thousands except for volumes and percentages)

	Three months ended September 30,		Change	Nine months ended September 30,		Change
	2006	2005		2006	2005	
Daily Sales Volumes – Average						
Oil & NGL (bbls/day)	5,221	5,293	(1%)	5,244	5,348	(2%)
Natural gas (mcf/day)	47,094	17,945	162%	43,550	10,022	335%
Total (boe/day)	13,070	8,284	58%	12,502	7,019	78%
Daily Sales Volumes - Exit Rate						
Oil & NGL (bbls/day)	4,714	5,361	(12%)	4,714	5,361	(12%)
Natural gas (mcf/day)	47,196	27,156	74%	47,196	27,156	74%
Total (boe/day)	12,580	9,887	27%	12,580	9,887	27%
Sales Volumes mix by product						
Oil & NGL	40%	64%		42%	76%	
Natural gas	60%	36%		58%	24%	
	100%	100%		100%	100%	

COMMODITY PRICING

Prices for oil received by the Trust decreased by 4% in Q3 2006 compared to Q3 2005. Natural gas prices received by the Trust decreased by 15% in Q3 2006 compared to Q3 2005. These decreases over the prior year reflect the exceptionally high market prices realized during the third quarter of 2005 due to the unusually large number of hurricanes that year and resultant impact on supply.

West Texas Intermediate ("WTI") is a standard benchmark for the price of oil. WTI is expressed in US dollars per barrel ("bbl"). The Trust reports the price it receives for oil in Canadian dollars per bbl. Alberta Spot prices, represented as AECO hub pricing ("AECO"), is a standard benchmark for the price of natural gas in Western Canada. AECO is expressed in Canadian dollars. New York Mercantile Exchange ("Nymex") is a standard benchmark for the price of natural gas in the United States.

WTI averaged US\$70.48/bbl for Q3 2006 compared to US\$63.19/bbl in Q3 2005. Alberta AECO was \$5.64/mcf for Q3 2006 compared to \$9.30/mcf for Q3 2005. Nymex averaged US\$6.53/mmbtu compared to US\$8.25/mmbtu for Q3 2005.

The Trust utilized a price risk management program to mitigate its exposure to price changes for oil and natural gas. Inclusive of this price risk management program, the Trust realized an average price of \$66.74/bbl of oil in Q3 2006 compared to \$69.60/bbl in Q3 2005 and \$7.47/mcf of natural gas in Q3 2006 compared to \$8.78/mcf in Q3 2005.

The Trust has the following hedges in place covering its oil and natural gas production:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collars	Gas	8.50 by 14.00 (Cdn \$/GJ)	5,000 GJ	October 1, 2006 – October 31, 2006
Collars	Gas	8.50 by 13.05 (Cdn \$/GJ)	5,000 GJ	October 1, 2006 – October 31, 2006
Collars	Gas	7.50 by 12.00 (Cdn \$/GJ)	7,500 GJ	November 1, 2006 – March 31, 2007
Collars	Gas	7.50 by 9.00 (Cdn \$/GJ)	10,000 GJ	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 12.00 (Cdn \$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Collars	Gas	6.75 by 8.75 (US \$/mmbtu)	4,000 mmbtu	October 1, 2006 – October 31, 2006
Collars	Gas	7.20 by 9.00 (US\$/mmbtu)	10,000 mmbtu	October 1, 2006 – October 31, 2006
Collars	Gas	8.00 by 15.70 (US \$/mmbtu)	12,000 mmbtu	November 1, 2006 – March 31, 2007
Collars	Gas	7.50 by 11.15 (US \$/mmbtu)	10,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 16.40 (US \$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collars	Oil	55.00 by 70.35 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 65.50 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 78.50 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 74.70 (US\$/bbl)	1,000 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	56.00 by 80.00 (US\$/bbl)	1,000 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 81.20 (US\$/bbl)	1,000 bbl	January 1, 2007 – June 30, 2007
Collars	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	January 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	January 1, 2007 – December 31, 2007
Fixed purchase	Power (Alberta)	62.90 (Cdn \$/Mw)	3 Mw/hour	October 1, 2006 – December 31, 2009

These hedging positions represent approximately 50% of the Trust's expected production on a boe/day basis for the balance of fiscal 2006.

Pricing (in thousands except for volumes and pricing)

	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Pricing Benchmarks						
WTI (US\$/bbl)	70.48	63.19	12%	68.22	55.40	23%
Average exchange rate: US\$1.00 to Cdn\$ =	1.12	1.20	(7%)	1.13	1.22	(7%)
WTI (Cdn\$/bbl)	78.94	75.83	4%	77.09	67.59	14%
AECO monthly index (Cdn\$/mcf)	5.64	9.30	(39%)	6.40	7.84	(18%)
Nymex (US\$/mmbtu)	6.53	8.25	(21%)	7.48	7.12	5%

Average Prices Received by the Trust

Oil (Cdn\$ per bbl)	\$66.74	\$69.60	(4%)	\$64.17	\$59.07	9%
Natural gas (Cdn\$ per mcf)	\$7.47	\$8.78	(15%)	\$7.40	\$8.02	(8%)
Total ⁽¹⁾ (Cdn\$ per boe)	\$53.26	\$62.50	(15%)	\$54.24	\$56.10	(3%)

(1) Includes NGL's

REVENUES

The positive impact on revenues, related to the increase in natural gas sales volumes, was partially offset by the decrease in sale prices of both oil and natural gas. While sales volumes increased by 58% in Q3, 2006, the total average price per boe received by the Trust declined by 15% period over period. The increase in natural gas sales volumes was a direct result of the High Point and Oklahoma Asset acquisitions. The decrease in the average sales price reflects the combined impact of weaker natural gas prices in 2006 following the exceptionally high prices realized in 2005 in the wake of Hurricane Katrina and other storms; gas sales representing a larger percentage of total sales volumes; and a stronger Canadian dollar.

Revenues (in thousands)

	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Revenues						
Oil and NGL	\$31,660	\$33,140	(4%)	\$90,341	\$85,540	6%
Natural gas	32,385	14,498	123%	87,955	21,955	301%
Total	\$64,045	\$47,638	34%	\$178,296	\$107,495	66%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, offset by Alberta Royalty Tax Credits (“ARTC”), have increased compared to the prior periods as the result of the increased revenues in the periods. Royalties are based on the volume of production or sales and commodity price, therefore royalties per boe fluctuate in relation to the fluctuation in the prices received by the Trust for the oil and natural gas sales.

Royalties (in thousands except for percentages and per boe amounts)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Royalties	\$12,342	\$10,487	18%	\$37,092	\$23,159	60%
As a percentage of revenue	19%	22%		21%	22%	
Royalties per boe	\$10.26	\$13.76	(25%)	\$10.87	\$12.09	(10%)

PRODUCTION EXPENSES

Per unit operating costs rose in Q3 2006 compared to Q3 2005. The increase is due to a large-scale well workover and maintenance program in Oklahoma in August and September 2006, the higher cost oil-weighted nature of the properties acquired in the JED swap, and general inflationary cost pressure. In addition, the Trust changed certain of its contracts whereby the Trust is now directly responsible for the transportation costs of its natural gas. As a result of this, approximately \$0.7 million is recorded as a production expense instead of a reduction of revenue.

Production Expenses (in thousands except for percentages and per boe amounts)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Production expenses	\$13,745	\$7,698	79%	\$32,791	\$21,613	52%
Production expenses per boe	\$11.43	\$10.10	13%	\$9.61	\$11.28	(15%)

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses (“G&A”) increased by 102% to \$4.9 million from \$2.4 million in Q3 2005 and by 74% to \$12.8 million from \$7.3 million for the nine months ended Q3 2005. The change is due to the increased asset base of the Trust and the associated increased personnel and administrative functions along with the increased costs associated with the Trust’s regulatory requirements. G&A per boe increased by 28% to \$4.07/boe in Q3 2006 compared to \$3.19/boe in Q3 2005. Within G&A, the non-cash unit based compensation increased to \$1.5 million in Q3 2006 from \$0.2 million in Q3 2005. This non-cash unit based compensation includes expenses for both unit option plans and the recently implemented performance and restricted unit plans.

General and Administrative Expenses (in thousands except for percentages and per boe amounts)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
G&A expenses	\$4,894	\$2,428	102%	12,767	\$7,341	74%
G&A per boe	\$4.07	\$3.19	28%	\$3.74	\$3.83	(2%)

INTEREST EXPENSE

Interest expense has increased mainly due to the financing of the Oklahoma Asset acquisitions. On March 21, 2006, the Trust entered into a Cdn\$110.0 million bridge credit facility to replace its current operating facilities (drawn to \$108.0 million as at September 30, 2006) as well as a US\$200.0 million bridge credit facility to partially finance the acquisitions of the Oklahoma Assets. These facilities were entered into as interim mechanisms for the financing of the Oklahoma Asset acquisitions.

Interest Expense (in thousands except for percentages and per boe amounts)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Debt, capital lease, and notes payable at end of period	\$336,595	\$107,187	214%	\$336,595	\$107,187	214%
Interest expense	\$8,202	\$1,365	501%	\$18,159	\$2,715	569%
Interest expense per boe	\$6.82	\$1.79	281%	\$5.32	\$1.42	275%

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

DD&A expense increased by 102% in Q3 2006 compared to Q3 2005, primarily due to the cost of the oil and natural gas properties acquired in the High Point and Oklahoma Asset acquisitions. The DD&A expense per boe increased 28% in Q3 2006 compared to Q3 2005 due to the higher cost of reserves associated with the acquisitions.

Depletion, Depreciation and Accretion (in thousands except for percentages and per boe amounts)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
DD&A	\$36,667	\$18,130	102%	\$99,281	\$40,417	146%
DD&A per boe	\$30.49	\$23.79	28%	\$29.09	\$21.09	38%

TAXES

Future income taxes primarily reflect the timing difference between the expensing of capital assets for accounting purposes and for tax purposes as well as a reduction in the tax rate of the Trust.

The acquisition of the Oklahoma Assets created minimal future income tax differences as the acquired assets will receive full tax basis for their acquired values.

On October 31, 2006, the Canadian federal government announced tax proposals pertaining to the taxation of Trusts and the tax treatment of Trust distributions to Unitholders. If enacted, the changes would result in the Trust being subject to a tax in a manner similar to corporations. The effect of the proposed changes may be mitigated by the fact that cash flow from the Trust’s Oklahoma Assets may not be subject to the new tax as it is cash flow generated from sources outside of Canada. Once the draft legislation is available and the Trust completes a full review and analysis of the impact that the legislation may have, we will report to our Unitholders. At present, indications are that the proposed legislation will only be applicable to the Trust effective January 1, 2011.

NON-GAAP FINANCIAL MEASURES

The Trust provides financial measures in the MD&A that do not have a standardized meaning prescribed by GAAP. These non-GAAP financial measures may not be comparable to similar measures presented by other entities.

The purpose of these financial measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures by the Trust.

Funds from Operations

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

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Cash provided by operating activities	\$11,692	\$16,622	\$38,322	\$47,545
Changes in non-cash working capital items	(13,589)	(7,318)	(38,237)	(3,481)
Funds from operations	\$25,281	\$23,940	\$76,559	\$51,026

In Q3 2006, funds from operations increased by 6% over Q3 2005. This increase is mainly due to the increased funds generated by the Oklahoma Asset acquisitions. The above noted increase to funds from operations was tempered slightly by increased interest expense associated with the interim financing arrangements as well as comparably lower prices for natural gas.

CASH DISTRIBUTIONS PAID TO UNITHOLDERS

The Trust pays monthly cash distributions in US dollars. Cash distributions are paid on the 15th of the following month (e.g. the October 2006 distribution will be paid on November 15, 2006). These distributions are determined each month by the board of directors of Enterra Energy Corp., as administrator of the Trust, after review of a number of factors potentially impacting the Trust including its available prospects and opportunities, the outlook for commodity prices and other macro-economic factors, and the Trust's financial position and commitments.

On July 18, 2006, the Trust announced a change to its target payout ratio, reducing it from 90% to 100% of funds from operations to a range of 60% to 70%. The effect was a decrease in the monthly distribution to US\$ 0.12 per unit compared to US\$0.18 per unit in June 2006. The June 2006 distribution of US\$0.18 was paid in July 2006, which is included in the cash distributed to Unitholders for the three months ended September 30, 2006.

The Trust's US\$200.0 million bridge financing agreement limits the Trust's ability to withdraw more than US\$1.5 million per month from its US operations. This restriction will be in place until the Trust replaces the bridge facility. The monthly cash distributions per trust unit since the inception of the Trust are as follows:

US\$	2006	2005	2004	2003
January	\$ 0.18	\$ 0.14	\$ 0.10	
February	\$ 0.18	\$ 0.14	\$ 0.10	
March	\$ 0.18	\$ 0.15	\$ 0.11	
April	\$ 0.18	\$ 0.15	\$ 0.11	
May	\$ 0.18	\$ 0.15	\$ 0.11	
June	\$ 0.18	\$ 0.16	\$ 0.12	

July	\$	0.12	\$	0.16	\$	0.12
August	\$	0.12	\$	0.16	\$	0.12
September	\$	0.12	\$	0.17	\$	0.13
October	\$	0.12	\$	0.17	\$	0.13
November			\$	0.17	\$	0.13
December			\$	0.18	\$	0.14
			\$		\$	0.10

	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	Change	2006	2005	Change
Cash distributions to Unitholders	\$21,083	\$16,918	25%	\$70,913	\$45,128	57%
Funds from operations	\$25,281	\$23,940	6%	\$76,559	\$51,026	50%
Cash distributions as a percentage of funds from operations	83%	71%		93%	88%	

The payout ratio in Q3 2006 was 83%, exceeding the target payout ratio of 60% to 70% of funds from operations, in part due to the higher level of distributions in July (June 2006 distribution of US\$ 0.18 was paid in July 2006). While the payout ratio was above the target range, after a review of the circumstances, the board of directors elected not to reduce the level of the distribution. However, the Trust will continue to monitor the payout ratio to ensure that over the medium and long term, the ratio remains in the target range. Had the Trust changed its target payout ratio prior to the June 2006 declaration, the cash distribution to Unitholders would have been \$3.0 million lower and would have resulted in a 72% cash distribution as a percentage of funds from operations for Q3 2006.

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

CAPITAL EXPENDITURES

A component of the Trust's business strategy is to invest available funds not distributed to Unitholders in lower-risk projects within core areas of its asset base. As well, the Trust continually seeks accretive acquisitions of oil and gas assets that will create new core areas with investment potential or will consolidate an existing core area. Any such purchases are financed with cash flows from operations, issuing new trust units or incurring new debt.

During Q1 and Q2 2006, the Trust acquired oil and natural gas properties located in Oklahoma. The Oklahoma Assets provide the Trust with future cash potential from their developed oil and natural gas production and their significant proved reserve base. The Trust acquired the assets in four stages.

Prior to closing the acquisitions, the Trust acquired \$49.7 million of notes payable by the primary vendors of the Oklahoma Assets. \$11.2 million of these notes was assumed by the Trust as consideration on the closing of the first stage of the acquisition. The remaining notes were repaid, by the vendors, to the Trust upon the second closing of the acquisition. The acquisition of the notes, by the Trust, was financed with a US\$50.0 million senior bridge credit facility.

On January 18, 2006, the Trust closed the first stage of the acquisition of the Oklahoma Assets. The results of the operations of the assets acquired are included in the Trust's consolidated financial statements as of January 18, 2006.

On March 21, 2006, the Trust closed the second stage of the acquisition of the Oklahoma Assets. Along with the second stage, the Trust acquired the operating company of the Oklahoma Assets. The results of operations of the assets acquired and the operating company are included in the Trust's consolidated financial statements as of March 21, 2006.

On April 4, 2006, the Trust closed the third stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 4, 2006.

On April 18, 2006, the Trust closed the fourth stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 18, 2006.

The total consideration paid for the acquisitions was \$307.4 million (5,685,028 units valued at \$116.5 million and \$182.2 million of cash, including transaction costs of \$8.6 million).

For each vendor, from the January 18, 2006 and March 21, 2006 closings, there was a six-month adjustment period for certain specifically identified adjustment wells, which could increase the cost of the acquisition. If the specifically identified wells produce an average volume (based on the best 30 day period of the last 60 days of the adjustment period) greater than the actual boe/day delivered on those wells at the closing date, the cost of the acquisition will increase by US\$36,000 per producing boe/day on the excess production of those wells. During Q2 2006, the adjustment was performed for the vendor from the January 18, 2006 closing, resulting in additional consideration of \$3.1 million being paid to the vendor. During Q3 2006, the adjustment was performed for the vendors from the March 21, 2006 closing, resulting in additional consideration of \$13.4 million being payable to the vendors.

On September 28, 2006, the Trust closed on a property swap agreement with JED whereby the Trust swapped certain of its interests in properties in the Ferrier area of Alberta, valued at \$44.0 million for interests of JED in common with the Trust in East Central Alberta, the Desan area of Northeast British Columbia and the Ricinus area of Alberta, valued at \$30.9 million. The swap was based on independent third party engineering evaluations. The transaction also resulted in the termination of the Agreement of Business Principles between the Trust and JED whereby the Trust had a right of first refusal on properties that JED owned and JED had the ability to farm-in on the Trust's undeveloped lands. Concurrent with the swap, the Trust settled all amounts owing to JED.

The following table represents the Trust's capital expenditures that were paid for with cash. The source of this cash was through private placements of trust units and excess funds from the bridge financing. The table excludes capital expenditures, such as the portion of the Oklahoma Asset acquisition, which was paid for with non-cash consideration such as trust units.

Capital Expenditures Paid with Cash (in thousands except for percentages)						
	Three months ended September 30,			Nine months ended September 30,		
	2006	2005	<i>Change</i>	2006	2005	<i>Change</i>
Capital expenditures	\$13,073	\$4,586	185%	\$207,957	\$24,436	751%

Capital additions for the nine months ended September 30, 2006 were \$403.8 million (nine months ended September 30, 2005 - \$24.4 million). In addition to the Oklahoma Asset acquisitions of \$353.5 million, the assets acquired through the JED swap of \$30.9 million and the capital expenditures paid with cash, \$1.2 million of net asset retirement obligations ("ARO") and \$0.4 million related to minority interest accounting as per EIC-151 were charged to property, plant and equipment. Total dispositions for the nine months ended September 30, 2006 were \$50.8 million (nine months ended September 30, 2005 - \$2.1 million).

The Trust accounts for its investment in the Oklahoma Assets as a self sustaining operation, which means the capital assets associated with the Oklahoma Assets (as well as all other balance sheet accounts for the

Oklahoma Assets) are subject to revaluation to the current exchange rate at each balance sheet date. The result of this revaluation is a change in the carrying value of the Oklahoma assets, which is not a result of capital additions or disposals.

LIQUIDITY & CAPITAL RESOURCES

The Trust's business strategy is to both develop its own reserves and undeveloped land as well as have other companies spend the capital to develop properties in exchange for a working interest. As well, the Trust continually seeks accretive acquisitions of oil and gas assets that will create new core areas with investment potential or will consolidate an existing core area. Any such capital expenditures or purchases by the Trust will be financed from cash flow, by issuing new equity and/or with debt.

In March 2006, the Trust closed a \$110.0 million senior secured bridge facility. This reducing non-revolving credit facility was used to repay the existing \$100.0 million credit facilities of the Trust. The facility bears interest at 2.5% above bank prime lending rates. \$2.0 million of the facility was repaid on June 30, 2006 and another payment of \$8.0 million is due by November 30, 2006. The facility matures on December 31, 2006. The facility is secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets. The credit facility requires the Trust to maintain certain financial covenants. At September 30, 2006, the Trust is required to calculate the financial covenants and report to its lenders within 45 days of that date. The Trust was in breach of certain financial covenants at September 30, 2006. The Trust has 10 days to remedy the breach, or obtain a waiver of the default from the lender, once it has received written notification of a covenant breach from the lender. The Trust does not expect to remedy the covenants by the end of the 10 day remediation period as it expects to repay the facility prior to that time.

In March 2006, the Trust closed a US\$200.0 million senior secured bridge credit facility to partially fund the acquisition of the Oklahoma Assets, repay the US\$50.0 million bridge credit facility noted above and provide working capital to the Trust. This non-revolving facility originally bore interest at 4.5% above London Interbank Offering Rate and matured September 20, 2006. The Trust exercised a one-time option to extend the facility to December 20, 2006. As a result of this extension, the interest rate increases by 1% per month. The facility is secured by a first charge over all US assets and a second charge over all Canadian assets. The terms of the credit facility restrict the Trust's ability to withdraw more than US\$1.5 million per month from the US segment. The credit facility requires the Trust to maintain certain financial covenants. As at September 30, 2006, the Trust had drawn \$223.5 million (US\$200.0 million) on the facility. At September 30, 2006, the Trust is required to calculate the financial covenants and report to its lender within 45 days. The Trust was in breach of certain financial covenants at September 30, 2006. The Trust has 20 days to remedy any breach or to obtain a waiver of the default from the lender once the breach is known. Failure to remedy the breach will result in the facility becoming due and payable immediately. The Trust does not expect to remedy the breaches by the end of the 20 day remediation period as it expects to repay the facility prior to that time.

On October 11, 2006, the Trust entered into an agreement with a syndicate of lenders for a \$180.0 million revolving extendible credit facility and a \$20.0 million revolving extendible operating credit facility. The facilities are subject to the Trust closing at least \$150.0 million of equity in the form of trust units or convertible debentures. The facilities are 364 day extendible facilities that are secured with a first priority charge over the Trust's assets. Borrowings under the facilities bear interest at banker's acceptance rates, Canadian or US prime rates, or LIBOR plus applicable margins ranging from nil to 1.65% depending on the form of borrowing and the Trust's debt to cash flow ratio. The initial margin is expected to be 0.4% on prime rate borrowings and 1.4% on banker's acceptance rates or LIBOR borrowing.

The Trust signed an underwriting agreement dated October 27, 2006 and on October 30, 2006 filed a preliminary prospectus for a bought deal for the issuance of \$120.0 million of 8.0% unsecured subordinated debentures convertible into units at a price of \$9.50 and \$35.0 million of trust units at a price of \$8.50. The Trust also granted to the underwriters an over-allotment option to purchase up to an additional \$5.3 million of trust units at the offering price and an additional \$18.0 million of debentures, exercisable up to 30 days from the closing of the offering. The offering was expected to close on November 9, 2006.

The Trust anticipated repaying the bridge credit facilities from the proceeds of the debenture and trust unit offering and drawing on the new credit facilities. However, on October 31, 2006, the federal government announced proposed tax legislation changes that could significantly impact how income trusts are taxed in Canada. The proposed tax legislation changes and the ensuing impact on the capital markets has caused the Trust and the underwriter to reconsider the offering. As a consequence, the closing which was originally scheduled to occur on November 9, 2006 was postponed.

On November 6, 2006, to ensure that the Trust is able to refinance the bridge facilities should the Trust and the underwriters elect to postpone the offering for an extended period of time, the Trust agreed to terms for a \$350.0 million senior secured bridge facility with one of its existing lenders. The facility is a reducing, non-revolving facility that bears interest at 2.5% above bank prime lending rates. The facility will be secured by a first charge over all of the Trust's assets and will mature on May 31, 2007. The facility will require the Trust to maintain certain financial covenants. The Trust must satisfy several conditions prior to being able to draw on the new bridge facility. There can be no assurances that the Trust will be able to satisfy the required conditions.

On November 9, 2006, the Trust signed a revised underwriting agreement for a bought deal for the issuance of \$120.0 million of 8.0% unsecured subordinated debentures convertible into units at a price of \$9.25 and \$35.0 million of trust units at a price of \$8.10. The Trust also granted to the underwriters an over-allotment option to purchase up to an additional \$5.3 million of trust units at the offering price and an additional \$18.0 million of debentures, exercisable up to 30 days from the closing of the offering. The offering is scheduled to close on November 21, 2006. The proceeds from the offering will be used to partially repay the US\$200.0 million senior secured bridge credit facility and the \$110.0 million senior secured bridge facility.

The Trust must refinance the bridge credit facilities through the equity offering and the related credit facilities or with the \$350.0 million bridge facility prior to the end of the remediation periods, being November 20, 2006 for the \$108.0 million facility and November 30, 2006 for the US\$200.0 million facility, or obtain waivers from the lenders with respect to the covenant violations.

If the Trust cannot refinance the existing credit facilities or obtain waivers, the existing lenders can require the Trust to suspend distributions to Unitholders. If alternative long term financing cannot be obtained, the ability of the Trust to continue as a going concern is uncertain.

<i>Working Capital (in thousands)</i>	September 30, 2006	December 31, 2005
Working capital (deficiency)	\$(316,429)	\$(112,397)
Working capital (deficiency) excluding debt	\$18,237	\$(16,947)

RELATIONSHIP WITH JED

On January 1, 2006, the Trust terminated the Technical Services Agreement with JED. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On February 1, 2006, the Trust repaid the \$8.0 million unsecured notes payable to JED that had been outstanding at December 31, 2005.

On September 28, 2006, the Trust terminated the existing farmout, joint services and business principles agreements with JED. Concurrent with the termination of the agreements, the Trust settled all (\$13.1 million) amounts owing to JED. At September 30, 2006, the Trust owed nil (December 31, 2005 - \$15.2 million) to JED for capital expenditures related to the terminated farm out agreement.

RELATED PARTY TRANSACTIONS

During Q3 2006 the Trust paid \$120,000 (Q3 2006 year to date - \$415,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and the previous Chief Financial Officer. At September 30, 2006 \$nil (December 31, 2005 - \$84,000) was payable by the Trust to Macon.

During Q1 2006 the Trust entered into a farmout agreement with Petroflow Energy Inc. ("Petroflow"), an oil and gas development company, to fund 100% of the drilling and completion costs of the Oklahoma Asset's undeveloped lands. The Chief Executive Officer for the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at September 30, 2006, the Trust had \$2.2 million of net receivables from Petroflow. The receivables are for reimbursement of actual costs incurred by the Trust and are due within 30 days. Subsequent to September 30, 2006 \$1.0 million was received from Petroflow. During Q3 2006, there were no revenues earned, nor expenses incurred to or from Petroflow.

During Q3 2006, the final adjustment period on the Oklahoma Asset acquisition concluded. As a result of the adjustment payment, the Trust owes \$4.1 million to a director of the Trust.

A director and an officer of the Trust have common interests, with the Trust, in certain of the Oklahoma Assets. As a result of the common interests certain balances will be payable or receivable due to normal operations of the common properties. At September 30, 2006 \$2.1 million was payable to the Trust from the director. This payable will netted against the settlement of the adjustment payment for the Oklahoma Assets. At September 30, 2006 no amounts were payable or receivable from the officer.

TRUST UNIT INFORMATION

The Trust is capitalized through a combination of trust units and exchangeable shares of certain of its subsidiaries. The Trust also has a unit option plan, restricted unit plan, performance unit plan and warrants to purchase trust units outstanding. The following table outlines outstanding equity instruments:

Outstanding unit data (units / shares)			
As at	October 31, 2006	September 30, 2006	December 31, 2005
Trust units	44,877,426	44,877,426	36,504,416
Exchangeable shares			
EEC exchangeable shares	16,337	16,337	348,146
RMG exchangeable shares	-	-	736,842
RMAC Series B exchangeable shares	67,350	67,350	659,116
Trust unit options	1,426,000	1,532,673	1,431,405
Restricted units	412,082	412,082	-
Performance units	200,479	200,479	-
Warrants	301,000	301,000	301,000

The exchangeable shares of the subsidiary corporations are not listed for trading on an exchange and are treated as a minority interest under GAAP. The exchangeable shares are convertible into trust units based on their respective exchange ratios.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

As at the three and nine month periods ended September 30, 2006, an evaluation was carried out under the supervision of and with the participation of the Trust's management, including the CEO and CFO, of the effectiveness of the Trust's disclosure controls and procedures. Based on that evaluation, the CEO and the CFO concluded that the design and operation of these disclosure controls and procedures were effective as at September 30, 2006 to provide reasonable assurance that material information relating to the Trust would be made known to them by others within the Trust.

CRITICAL ACCOUNTING ESTIMATES

The Trust continues to evolve and document its management and internal reporting systems to provide assurance that accurate, timely internal and external information is gathered and disseminated. The Trust's financial and operating results incorporate certain estimates including:

- a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- b) estimated capital expenditures on projects that are in progress;
- c) estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves, which the Trust expects to recover in the future;
- d) estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
- e) estimated future recoverable value of property, plant and equipment and goodwill.

The operations of the Oklahoma Assets are considered to be self-sustaining. As a result, the revenues and expenses of this division are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in the cumulative translation account in Unitholders' equity.

ADDITIONAL INFORMATION

Additional information relating to Enterra Energy Trust, including our Annual Information Forms and Annual Reports, can be found on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar.shtml, as well as on the Trust's website at www.enterraenergy.com.

QUARTERLY FINANCIAL INFORMATION

	2006				2005			2004
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenues	\$64,045	\$65,936	\$48,315	\$50,248	\$47,638	\$29,807	\$30,050	\$33,593
Earnings (loss) before taxes and non-controlling interest	\$(6,879)	\$(10,579)	\$(3,149)	\$(28,526)	\$ 7,530	\$947	\$3,757	\$3,103
Net earnings (loss)	\$3,000	\$(296)	\$2,248	\$(12,937)	\$7,089	\$2,567	\$4,251	\$3,256
Net earnings (loss) per trust unit								
Basic	\$0.07	\$(0.01)	\$0.06	\$(0.37)	\$0.23	\$0.10	\$0.16	\$0.13
Diluted	\$0.07	\$(0.01)	\$0.06	\$(0.37)	\$0.23	\$0.10	\$0.16	\$0.13
Distributions declared (US\$)	\$0.36	\$0.54	\$0.54	\$0.52	\$0.49	\$0.46	\$0.43	\$0.40

The quarterly information reflects a general trend to increasing revenues reflecting the overall growth of the Trust and the rising price of the oil and natural gas sold by the Trust.

ABBREVIATIONS

bbl	barrel of oil
bbls/day	barrels of oil per day
mcf	thousand cubic feet of natural gas
mcf/day	thousands of cubic feet of natural gas per day
mmcf/day	millions of cubic feet of natural gas per day
NGL	natural gas liquids
boe	barrels of oil equivalent (6 mcf equivalent to 1 bbl)
mboe	thousands of barrels of oil equivalent
boe/day	barrels of oil equivalent per day
GJ	Gigajoule
mmbtu	Millions of British Thermal Units
CICA	Canadian Institute of Chartered Accountants
GAAP	Canadian Generally Accepted Accounting Principles
Cdn\$	Canadian dollars
US\$	United States dollars
WTI	West Texas Intermediate (Oil reference price)
AEEO	Natural gas reference price in Alberta
Nymex	New York Mercantile Exchange
Q1	First quarter of the year - January 1 to March 31
Q2	Second quarter of the year - April 1 to June 30
Q3	Third quarter of the year - July 1 to September 30
Q4	Fourth quarter of the year - October 1 to December 31
Unitholders	The holders of the Trust Units

ENTERRA ENERGY TRUST

CONSOLIDATED BALANCE SHEETS

(Thousands of Canadian dollars)

(unaudited)

	September 30, 2006	December 31, 2005
Assets		
Current assets		
Cash	\$ 13,657	\$ 11,943
Accounts receivable	39,396	35,303
Financial derivatives (note 8)	10,159	415
Prepaid expenses, deposits and other	3,863	3,052
	67,075	50,713
Property, plant and equipment (note 4)	731,437	489,074
Deferred financing charges, net	5,268	1,210
Goodwill	76,256	70,546
	\$ 880,036	\$ 611,543
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ 38,926	\$ 36,348
Due to JED Oil Inc. (note 12)	-	15,151
Distribution payable to unitholders	5,986	7,699
Income taxes payable	2,871	2,066
Debt (note 2)	334,666	95,450
Note payable	-	4,071
Marketing contracts and financial derivatives (note 8)	119	1,447
Current portion of capital lease	936	878
	383,504	163,110
Asset retirement obligations (note 5)	27,474	24,323
Future income tax liability	74,137	100,297
Capital lease	993	1,702
	486,108	289,432
Non-controlling interest (note 6)	1,848	32,402
Unitholders' Equity (note 7)		
Unitholders' capital	543,100	373,761
Warrants	1,215	1,215
Contributed surplus	2,670	573
Deficit	(150,089)	(85,840)
Cumulative translation adjustment	(4,816)	-
	392,080	289,709
Debt and need to refinance (note 2)		
Subsequent events (note 2)	\$ 880,036	\$ 611,543

See accompanying notes to consolidated financial statements

Approved on behalf of the Board:

*

("signed")
Keith Conrad
Director

("signed")
Joseph Vidal
Director

ENTERRA ENERGY TRUST

CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT

(Thousands of Canadian dollars, except per trust unit amounts)

(unaudited)

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Revenues				
Oil and natural gas	\$ 64,045	\$ 47,638	\$ 178,296	\$ 107,495
Royalties	(12,342)	(10,487)	(37,092)	(23,159)
	51,703	37,151	141,204	84,336
Expenses				
Operating	13,745	7,698	32,791	21,613
General and administrative	4,894	2,428	12,767	7,341
Interest	8,202	1,365	18,159	2,715
Financing fees	3	-	382	-
Amortization of deferred financing charges	4,018	-	7,975	16
Depletion, depreciation and accretion	36,667	18,130	99,281	40,417
Financial derivative gain	(9,290)	-	(10,069)	-
Foreign exchange loss	343	-	526	-
	58,582	29,621	161,812	72,102
Earnings (loss) before taxes and non-controlling interest	(6,879)	7,530	(20,608)	12,234
Income tax expense (reduction)				
Current	681	933	681	1,102
Future	(10,566)	(888)	(26,305)	(3,364)
Earnings before non-controlling interest	3,006	7,485	5,016	14,496
Non-controlling interest (note 6)	6	396	65	589
Net earnings	3,000	7,089	4,951	13,907
Distributions declared	(18,138)	(18,659)	(69,200)	(47,695)
Deficit, beginning of period	(134,951)	(39,532)	(85,840)	(17,314)
Deficit, end of period	\$ (150,089)	\$ (51,102)	\$ (150,089)	\$ (51,102)
Net earnings per trust unit (note 7)				
Basic	\$ 0.07	\$ 0.23	\$ 0.12	\$ 0.50
Diluted	\$ 0.07	\$ 0.23	\$ 0.11	\$ 0.50

See accompanying notes to consolidated financial statements

ENTERRA ENERGY TRUST

CONSOLIDATED STATEMENTS OF CASH FLOW

(Expressed in thousand Canadian dollars)

(unaudited)

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Cash provided by (used in):				
Operating				
Net earnings	\$ 3,000	\$ 7,089	\$ 4,951	\$ 13,907
Depletion, depreciation and accretion	36,667	18,130	99,281	40,417
Future income tax reduction	(10,566)	(888)	(26,305)	(3,364)
Amortization of deferred financing charges	4,018	-	7,975	16
Financial derivatives	(9,290)	-	(10,069)	-
Amortization of marketing contract	-	(1,007)	(1,447)	(1,007)
Non-controlling interest	6	396	65	589
Foreign exchange	(22)	-	(592)	-
Unit-based compensation	1,468	220	2,700	468
Changes in non-cash working capital items	(13,589)	(7,318)	(38,237)	(3,481)
	11,692	16,622	38,322	47,545
Financing				
Distributions paid	(21,083)	(16,918)	(70,913)	(45,128)
Bank indebtedness	-	(9,839)	(99,739)	(23,159)
Bridge credit facilities	-	-	401,242	-
Bridge credit facility repayment	-	-	(60,630)	-
Repayment of debt assumed on Oklahoma Asset acquisition	(8)	-	(14,164)	-
Capital lease	(222)	(203)	(651)	(597)
Proceeds from (repayment of) notes	-	4,399	(3,990)	4,399
Deferred financing charges	(887)	(186)	(10,297)	(186)
Due to JED Oil Inc., net	4,846	3,376	(2,052)	10,377
Issue of trust units, net of issue costs	(12)	(187)	12,247	11,478
Exercise of trust unit options	-	2,001	1,399	7,415
	(17,366)	(17,557)	152,452	(35,401)
Investing				
Property, plant and equipment additions	1,181	(4,586)	(17,107)	(24,436)
Deposit on acquisition	-	-	-	2,400
Proceeds on disposal of property, plant and equipment	238	-	6,789	2,104
Acquisition of Oklahoma Assets (note 3)	(14,254)	-	(190,850)	-
Acquisition of Rocky Mountain Gas, Inc.	-	(249)	-	(83)
Acquisition of High Point	-	1,282	-	1,282
Changes in capital accounts payable	13,283	4,771	12,108	4,866
	448	1,218	(189,060)	(13,867)
Change in cash	(5,226)	283	1,714	(1,723)
Cash, beginning of period	18,883	2,773	11,943	4,779
Cash, end of period	\$ 13,657	\$ 3,056	\$ 13,657	\$ 3,056

During the nine month period ended September 30, 2006 the Trust paid interest of \$16,789 (nine months ended September 30, 2005 - \$2,715) and taxes of \$nil (nine months ended September 30, 2005 - \$1,102).

See accompanying notes to consolidated financial statements

Enterra Energy Trust
Notes to Consolidated Financial Statements

As at September 30, 2006 and for the three and nine months ended September 30, 2006 and 2005
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

1. Basis of Presentation

The interim consolidated financial statements of Enterra Energy Trust (the "Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles. These 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, 2005, 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 amended consolidated financial statements have been condensed or omitted.

2. Debt and Need to Refinance

On January 18, 2006, the Trust drew on a US\$50.0 million senior bridge credit facility to secure the acquisition of the Oklahoma Assets. The facility was a reducing non-revolving loan secured by a first charge over the notes from the sellers of the Oklahoma Assets. The loan bore interest at U.S. dollar commercial loan rate plus 0.5% and was repaid on March 22, 2006.

In March 2006, the Trust closed a \$110.0 million senior secured bridge facility. This reducing non-revolving credit facility was used to repay the existing \$100.0 million credit facilities of the Trust. The facility bears interest at 2.5% above bank prime lending rates. \$2.0 million of the facility was repaid on June 30, 2006 and another payment of \$8.0 million is due by November 30, 2006. The facility matures on December 31, 2006. The facility is secured by a first charge over all Canadian assets of the Trust and a second charge over all US assets. The credit facility requires the Trust to maintain certain financial covenants. The Trust was in breach of certain of the financial covenants at September 30, 2006. Failure to remedy any breach, or to obtain a waiver of the breach from the lender, will result in the facility becoming due and payable immediately. The Trust does not expect to remedy the covenant breaches as it expects to repay the facility prior to that time.

In March 2006, the Trust closed a US\$200.0 million senior secured bridge credit facility to partially fund the acquisition of the Oklahoma Assets, repay the US\$50.0 million bridge credit facility noted above and provide working capital to the Trust. This non-revolving facility originally bore interest at 4.5% above London Interbank Offering Rate and matured September 20, 2006. The Trust exercised a one-time option to extend the facility to December 20, 2006. As a result of this extension, the interest rate increases by 1% per month. The facility is secured by a first charge over all US assets and a second charge over all Canadian assets. The terms of the credit facility restrict the Trust's ability to withdraw more than US\$1.5 million per month from the US segment. The credit facility requires the Trust to maintain certain financial covenants. As at September 30, 2006, the Trust had drawn \$223.5 million (US\$200.0 million) on the facility. The Trust was in breach of certain financial covenants at September 30, 2006. Failure to remedy any breach, or to obtain a waiver of the breach from the lender, will result in the facility becoming due and payable immediately. The Trust does not expect to remedy the covenant breaches as it expects to repay the facility prior to that time.

On October 11, 2006, the Trust entered into an agreement with a syndicate of lenders for a \$180.0 million revolving extendible credit facility and a \$20.0 million revolving extendible operating credit facility. The facilities are subject to the Trust closing at least \$150.0 million of equity in the form of trust units or convertible debentures. The facilities are 364 day extendible facilities that are secured with a first priority charge over the Trust's assets. Borrowings under the facilities bear interest at banker's acceptance rates, Canadian or US prime rates or LIBOR plus applicable margins ranging from nil to 1.65% depending on the form of borrowing and the Trust's debt to cash flow ratio. The initial margin is expected to be 0.4% on prime rate borrowings and 1.4% on banker's acceptance rates or LIBOR borrowing. The Trust expects to draw on the facilities to partially repay the balance of the

Enterra Energy Trust
Notes to Consolidated Financial Statements

As at September 30, 2006 and for the three and nine months ended September 30, 2006 and 2005
(Expressed in Canadian Dollars)
(Tabular amounts are stated in thousands of dollars except unit and per unit information)

US\$200.0 million senior secured bridge credit facility and the \$110.0 million senior secured bridge facility.

The Trust signed an underwriting agreement dated October 27, 2006 and on October 30, 2006 filed a preliminary prospectus for a bought deal for the issuance of \$120.0 million of 8.0% unsecured subordinated debentures convertible into units at a price of \$9.50 and \$35.0 million of trust units at a price of \$8.50. The Trust also granted to the underwriters an over-allotment option to purchase up to an additional \$5.3 million of trust units at the offering price and an additional \$18.0 million of debentures, exercisable up to 30 days from the closing of the offering. The offering was expected to close on November 9, 2006. The proceeds from the offering were to be used to partially repay the US\$200.0 million senior secured bridge credit facility and the \$110.0 million senior secured bridge facility.

On October 31, 2006, the federal government announced proposed tax legislation changes that could significantly impact how income trusts are taxed in Canada. The proposed tax legislation changes and the ensuing impact on the capital markets caused the Trust and the underwriters to reconsider the offering. As a consequence, the closing which was originally scheduled to occur on November 9, 2006 was postponed.

On November 6, 2006, to ensure that the Trust is able to refinance the bridge facilities should the Trust and the underwriters elect to postpone the offering for an extended period of time, the Trust agreed to terms for a \$350.0 million senior secured bridge facility with one of its existing lenders. The facility is a reducing, non-revolving facility that bears interest at 2.5% above bank prime lending rates. The facility will be secured by a first charge over all of the Trust's assets and will mature on May 31, 2007. The facility will require the Trust to maintain certain financial covenants. The Trust must satisfy several conditions prior to being able to draw on the new bridge facility. There can be no assurances that the Trust will be able to satisfy the required conditions.

On November 9, 2006, the Trust signed a revised underwriting agreement for a bought deal for the issuance of \$120.0 million of 8.0% unsecured subordinated debentures convertible into units at a price of \$9.25 and \$35.0 million of trust units at a price of \$8.10. The Trust also granted to the underwriters an over-allotment option to purchase up to an additional \$5.3 million of trust units at the offering price and an additional \$18.0 million of debentures, exercisable up to 30 days from the closing of the offering. The offering is scheduled to close on November 21, 2006. The proceeds from the offering will be used to partially repay the US\$200.0 million senior secured bridge credit facility and the \$110.0 million senior secured bridge facility.

The Trust must refinance the bridge credit facilities through the equity offering and the related credit facilities or with the \$350.0 million bridge facility prior to the end of the remediation periods, being November 20, 2006 for the \$108.0 million facility and November 30, 2006 for the US\$200.0 million facility, or obtain waivers from the lenders with respect to the covenant violations.

If the Trust cannot refinance the existing credit facilities or obtain waivers, the existing lenders can require the Trust to suspend distributions to unitholders. If alternative long term financing cannot be obtained, the ability of the Trust to continue as a going concern is uncertain.

3. Acquisitions

During 2006, the Trust acquired oil and natural gas properties located in Oklahoma ("Oklahoma Assets"). The Trust acquired the assets in four stages.

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Prior to closing the acquisitions, the Trust acquired \$49.7 million of notes payable by the primary vendors of the Oklahoma Assets; as a result the vendors owed the Trust \$49.7 million. The primary vendors repaid the Trust \$38.5 million of the notes upon closing the second stage of the acquisition of the Oklahoma Assets. The acquisition of the notes, by the Trust, was financed with a US\$50.0 million senior bridge credit facility.

On January 18, 2006, the Trust closed the first stage of the acquisition of the Oklahoma Assets. The results of the operations of the assets acquired are included in the Trust's consolidated financial statements as of January 18, 2006.

On March 21, 2006, the Trust closed the second stage of the acquisition of the Oklahoma Assets. Along with the second stage, the Trust acquired the operating company of the Oklahoma Assets. The results of operations of the assets acquired and the operating company are included in the Trust's consolidated financial statements as of March 21, 2006.

On April 4, 2006, the Trust closed the third stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 4, 2006.

On April 18, 2006, the Trust closed the fourth stage of the acquisition of the Oklahoma Assets. The results of operations of the assets acquired are included in the Trust's consolidated financial statements as of April 18, 2006.

The acquisition was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Current assets	\$ 6,412
Property, plant and equipment	353,534
Current liabilities	(25,355)
Financial derivatives	(485)
Debt	(24,036)
Asset retirement obligations	(2,695)
	<hr/>
	\$ 307,375
	<hr/>
Cost of acquisitions:	
Cash	\$ 182,230
Transaction costs	8,620
5,685,028 trust units	116,525
	<hr/>
	\$ 307,375

The purchase price allocation is preliminary and subject to change. The value assigned to each Enterra Trust Unit of \$20.51 (US\$17.70) was based on the weighted average trading price on the New York Stock Exchange immediately prior to the measurement date. For each of the January 18, 2006 and the March 21, 2006 closings there was a six-month adjustment period for certain specifically identified adjustment wells, which could increase the cost of the acquisition. If the specifically identified wells produce an average volume (based on the best 30 day period in the last 60 days of the adjustment period) greater than the actual production acquired at closing, the cost of the acquisition will increase by US\$36,000 per producing boe/day on the excess production of those wells. During Q2 2006, the

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adjustment was calculated for the January 18, 2006 closing, resulting in additional consideration of \$3.1 million being paid to the vendor. During Q3 2006, the adjustments were calculated for the March 21, 2006 closings, resulting in additional consideration of \$13.4 million being payable to the vendors.

The operations of the Oklahoma Assets are considered to be self-sustaining. As a result, the revenues and expenses of this segment are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in the cumulative translation account in unitholders' equity.

Certain credit facilities were acquired in conjunction with the acquisition of the Oklahoma assets which are comprised of the following: (a) a US\$4.5 million unsecured revolving credit facility that bears interest at bank prime. The facility was repaid on October 20, 2006; (b) a building mortgage, secured by the building, that bears interest at 7% per annum. The mortgage matures on July 1, 2020. As at September 30, 2006, the loan had a balance of \$0.3 million (US\$0.3 million); (c) a promissory note, used to acquire, and secured by, equipment owned by the operating company of the Oklahoma Assets. The note matures on February 20, 2009 and bears interest at US prime plus 1%. At September 30, 2006, the balance of the note was \$0.1 million (US\$0.1 million).

4. Property, Plant and Equipment

	September 30, 2006		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	\$982,877	\$(253,904)	\$728,973
Office furniture and equipment	4,287	(1,823)	2,464
	\$987,164	\$(255,727)	\$731,437

	December 31, 2005		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties	\$644,260	\$(156,445)	\$487,815
Office furniture and equipment	2,781	(1,522)	1,259
	\$647,041	\$(157,967)	\$489,074

On September 28, 2006, the Trust sold \$44.0 million of petroleum and natural gas properties to JED Oil Inc. in exchange for \$30.9 million of petroleum and natural gas properties and the settlement of the \$13.1 million balance due to JED Oil Inc.

At September 30, 2006, included in petroleum and natural gas properties are assets acquired and pledged under capital lease agreements with a cost of \$5,218,000 and net book value of \$2,182,000 (December 31, 2005 - \$5,218,000 and \$2,597,000).

At September 30, 2006 costs of undeveloped land and seismic of \$37,519,000 (December 31, 2005 - \$58,353,000) were excluded from the calculation of depletion expense for the Canadian cost centre. At September 30, 2006 costs of undeveloped land of \$8,410,000 (December 31, 2005 - \$13,313,000) were excluded from the calculation of depletion expense for the United States cost centre.

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Depletion and depreciation expense related to the Canadian and the US cost center for the three months ended September 30, 2006 was \$23,906,000 and \$12,246,000 respectively and for the nine months ended September 30, 2006 was \$68,649,000 and \$29,124,000, respectively (U.S. cost center three and nine months ended September 30, 2005 – \$847,000, Q1 and Q2 2005 – no US cost center).

5. Asset Retirement Obligations

The asset retirement obligations were estimated by management based on the Trust's working interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred. At September 30, 2006, the Trust estimated the asset retirement obligation to be \$24,474,000 (December 31, 2005 – \$24,323,000), based on a total future liability of \$47,825,000 (December 31, 2005 - \$41,074,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently averages at 7 years, but extends up to 20 years into the future. This amount has been calculated using an inflation rate of 2% and discounted using a credit-adjusted risk-free interest rate of 8%.

The following table reconciles the asset retirement obligations:

Asset retirement obligation, December 31, 2005	\$	24,323
Increases (decrease) in liabilities during the period related to:		
Acquisitions		2,695
Additions		1,190
Accretion expense		1,508
Settlement of obligations		(1,959)
Foreign exchange		(283)
Asset retirement obligation, September 30, 2006	\$	27,474

6. Non-controlling Interest ("NCI")

Number of exchangeable shares issued	EEC	RMG	RMAC series B	Total
Balance at December 31, 2005	348,146	736,842	659,116	1,744,104
Exchanged for trust units	(331,809)	(736,842)	(591,766)	(1,660,417)
Balance at September 30, 2006	16,337	-	67,350	83,687

Non-controlling interest

	Amount
Balance at December 31, 2005	\$ 32,402
Exchanged for trust units	(30,619)
Non-controlling interest in net earnings	65
Balance at September 30, 2006	\$ 1,848

During Q3 2006, a total of 25,000 (Q1, Q2 and Q3 2006 – 331,809) Enterra Energy Corp. exchangeable shares were converted into 33,480 (Q1, Q2 and Q3 2006 – 422,397) trust units at an

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exchange ratio prevailing at the time of conversion. During Q3 2006, a total of 23,221 (Q1, Q2 and Q3 2006 – 591,766) RMAC series B exchangeable shares were converted into 26,096 (Q1, Q2 and Q3 2006 – 619,193) trust units at an exchange ratio prevailing at the time of conversion. During Q2 2006, all of the 736,842 RMG exchangeable shares were converted into 736,842 trust units. The exchange of the EEC exchangeable shares is treated as a step acquisition, which increased goodwill by \$0.5 million in Q3 2006 (Q3 2006 year to date - \$5.6 million) for the difference between the fair value of the trust unit issued and the carrying value of the EEC exchangeable share at the time of exchange.

At September 30, 2006 the exchange ratio for Enterra Energy Corp. exchangeable shares was 1.33920 and for RMAC series B exchangeable shares was 1.14482.

7. Unitholders' Equity

Authorized trust units

An unlimited number of trust units may be issued.

The trust units are redeemable at the option of the holder based on the lesser of 90% of the average market trading price of the trust units for the 10 trading days after the date of redemption or the closing market price of the trust units on the date of redemption. Trust units can be redeemed to a cash limit of \$100,000 per year or a greater limit at the discretion of the Trust. Redemptions in excess of the cash limit shall be satisfied first by the issuance of notes by a subsidiary of the Trust and second by issuance of promissory notes by the Trust.

Issued trust units

	Number of Units	Amount
Balance at December 31, 2005	36,504,416	\$ 373,761
Issued for cash pursuant to private placements	657,500	12,544
Issued on acquisition of Oklahoma Assets (note 2)	5,685,028	116,525
Issued as financing fees	116,054	2,077
Issued for exchangeable shares	1,778,432	36,488
Issued under restricted unit plan	36,091	575
Issued on exercise of options	99,905	1,427
Unit issue costs	-	(297)
Balance at September 30, 2006	44,877,426	\$ 543,100

Contributed surplus

	Amount
Balance at December 31, 2005	\$ 573
Trust unit option based compensation	942
Restricted and performance unit compensation	1,758
Transfer to trust units on option exercise	(28)
Transfer to trust units on restricted unit grant	(575)
Balance at September 30, 2006	\$ 2,670

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Trust unit options

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

The following options have been granted:

	Number of options	Weighted-average exercise price
Options outstanding, December 31, 2005	1,431,405	\$ 22.31
Options granted	677,000	16.57
Options exercised	(99,905)	14.00
Options cancelled	(475,827)	23.04
Options outstanding, September 30, 2006	1,532,673	\$ 20.84
Options exercisable, September 30, 2006	311,669	\$ 23.81

Estimated fair value of stock options

The estimated fair value of options granted in 2006 was determined using the Black-Scholes model under the following assumptions:

	2006
Weighted-average fair value of options granted (\$/option)	\$1.05
Risk-free interest rate (%)	4%
Estimated hold period prior to exercise (years)	5
Expected volatility (%)	45%
Expected cash distribution yield (%)	14%
Forfeiture rate (%)	10%

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Restricted and Performance units

The Trust has granted restricted and performance units to directors, officers, employees and consultants of the Trust. Restricted units ("RU's") vest over a contracted period and provide the holder with trust units on the vesting dates of the RU's. The actual units granted is based on the number of restricted units granted times a multiplier. The multiplier starts at 1.0 and is adjusted each month based on the monthly distribution of the Trust divided by the five day weighted average price of the Trust's units based on the New York Stock Exchange for the period preceding the distribution date. Performance units ("PU's") vest at the end of two years and provide the holder with trust units based on the same multiplier as the RU's as well as a payout multiplier. The payout multiplier ranges between 0.0 and 2.0 based on the Trust's total unitholder return compared to its peers.

The following restricted and performance units have been granted:

	Number of restricted units	Weighted- average grant date fair value	Number of performance units	Weighted- average grant date fair value
Units outstanding, December 31, 2005	-	\$ -	-	\$ -
Granted	452,170	15.22	202,650	15.39
Vested	(34,886)	15.66	-	-
Cancelled	(5,202)	15.66	(2,171)	15.66
Units outstanding, September 30, 2006	412,082	\$ 15.18	200,479	\$ 15.39

Reconciliation of earnings per unit calculations

For the three months ended September 30, 2006			
	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 3,000	44,815,633	\$ 0.07
Exchangeable shares / Non-controlling interest	6	139,200	
Restricted and performance units assumed exercised		612,561	
Diluted	\$ 3,006	45,567,394	\$ 0.07

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For the nine months ended September 30, 2006			
	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 4,951	42,364,523	\$ 0.12
Exchangeable shares / Non-controlling interest	65	807,876	
Restricted and performance units assumed exercised		612,561	
Options assumed exercised		435,000	
Units assumed purchased		(399,509)	
Diluted	\$ 5,016	43,820,451	\$ 0.11

For the calculation of the weighted average number of diluted units outstanding for the three months ended September 30, 2006, the unit options and warrants were excluded, as they were anti-dilutive to the calculation.

For the calculation of the weighted average number of diluted units outstanding for the nine months ended September 30, 2006, 1,097,673 unit options and 301,000 warrants were excluded, as they were anti-dilutive to the calculation.

For the three months ended September 30, 2005			
	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 7,089	31,052,000	\$ 0.23
Exchangeable shares / Non-controlling interest	396	1,753,948	
Options assumed exercised		1,277,500	
Units assumed purchased		(985,411)	
Diluted	\$ 7,485	33,098,037	\$ 0.23

For the nine months ended September 30, 2005			
	Net Earnings	Weighted Average Units Outstanding	Per Unit
Basic	\$ 13,907	27,590,771	\$ 0.50
Exchangeable shares / Non-controlling interest	589	967,597	
Options assumed exercised		1,277,500	
Units assumed purchased		(1,085,459)	
Diluted	\$ 14,496	28,750,409	\$ 0.50

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8. Financial Instruments

The Trust has entered into derivative financial instruments and fixed price physical contracts to minimize the risk of exposure to fluctuations in crude oil and natural gas prices and electricity costs. At September 30, 2006, the Trust had the following financial derivatives outstanding:

Derivative Instrument	Commodity	Price	Volume (per day)	Period
Collars	Gas	8.50 by 14.00 (Cdn \$/GJ)	5,000 GJ	October 1, 2006 – October 31, 2006
Collars	Gas	8.50 by 13.05 (Cdn \$/GJ)	5,000 GJ	October 1, 2006 – October 31, 2006
Collars	Gas	7.50 by 12.00 (Cdn \$/GJ)	7,500 GJ	November 1, 2006 – March 31, 2007
Collars	Gas	7.50 by 9.00 (Cdn \$/GJ)	10,000 GJ	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 12.00 (Cdn \$/GJ)	10,000 GJ	November 1, 2007 – March 31, 2008
Collars	Gas	6.75 by 8.75 (US \$/mmbtu)	4,000 mmbtu	October 1, 2006 – October 31, 2006
Collars	Gas	7.20 by 9.00 (US\$/mmbtu)	10,000 mmbtu	October 1, 2006 – October 31, 2006
Collars	Gas	8.00 by 15.70 (US \$/mmbtu)	12,000 mmbtu	November 1, 2006 – March 31, 2007
Collars	Gas	7.50 by 11.15 (US \$/mmbtu)	10,000 mmbtu	April 1, 2007 – October 31, 2007
Collars	Gas	8.00 by 16.40 (US \$/mmbtu)	10,000 mmbtu	November 1, 2007 – March 31, 2008
Collars	Oil	55.00 by 70.35 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 65.50 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 78.50 (US\$/bbl)	500 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 74.70 (US\$/bbl)	1,000 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	56.00 by 80.00 (US\$/bbl)	1,000 bbl	October 1, 2006 – December 31, 2006
Collars	Oil	55.00 by 81.20 (US\$/bbl)	1,000 bbl	January 1, 2007 – June 30, 2007
Collars	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	January 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 80.50 (US\$/bbl)	1,000 bbl	July 1, 2007 – December 31, 2007
Collars	Oil	55.00 by 78.60 (US\$/bbl)	500 bbl	January 1, 2007 – December 31, 2007
Fixed purchase	Power (Alberta)	62.90 (Cdn \$/Mw)	3 Mw/hour	October 1, 2006 – December 31, 2009

The estimated fair market value of the financial derivatives at September 30, 2006 are assets of \$10.2 million and liabilities of \$0.1 million for a net mark to market position of \$10.1 million.

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9. Contingencies

Certain claims have been brought against the Trust in the ordinary course of business. In the opinion of management, all such claims are adequately covered by insurance, or if not so covered, are not expected to materially affect the Trust's financial position.

10. Segmented Information

The Trust has one operating segment that is divided amongst two geographical areas. The following is selected financial information from the two geographic areas.

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Revenue				
Canada	\$ 39,640	\$ 45,571	\$ 119,540	\$ 105,428
U.S.	24,405	2,067	58,756	2,067
	\$ 64,045	\$ 47,638	\$ 178,296	\$ 107,495
Property, plant and equipment				
Canada			\$ 398,419	\$ 483,998
U.S.			333,018	35,336
			\$ 731,437	\$ 519,334
Goodwill				
Canada			\$ 76,256	\$ 73,184
U.S.			-	9,253
			\$ 76,256	\$ 82,437

11. Related Parties

During Q3 2006 the Trust paid \$120,000 (Q3 2006 year to date - \$415,000) to Macon Resources Ltd. ("Macon"), a company 100% owned by the Chief Executive Officer of the Trust, for management services provided by the Chief Executive Officer and the former Chief Financial Officer. At September 30, 2006 \$nil (December 31, 2005 - \$84,000) was payable by the Trust to Macon.

During Q1 2006 the Trust entered into a farmout agreement with Petroflow Energy Inc. ("Petroflow"), a public oil and gas development company, whereby Petroflow has agreed to fund 100% of the drilling and completion costs of the Oklahoma Asset's undeveloped lands. The Chief Executive Officer for the Trust owns, directly and indirectly, approximately 14% of the outstanding shares of Petroflow. As at September 30, 2006, the Trust had \$2.2 million of net receivables from Petroflow. The receivables are for reimbursement of actual costs incurred by the Trust and are due within 30 days. Subsequent to September 30, 2006 \$1.0 million was received from Petroflow. During Q3 2006, there were no revenues earned, nor expenses incurred to or from Petroflow.

During Q3 2006, the final adjustment period on the Oklahoma Asset acquisition concluded. As a result of the adjustment payment, at September 30, 2006 the Trust owes \$4.1 million to a director of the Trust who was a former owner of the Oklahoma Assets.

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A director and an officer of the Trust have common interests, with the Trust, in certain of the Oklahoma Assets. As a result of the common interests certain balances will be payable or receivable due to normal operations of the common properties. At September 30, 2006 \$2.1 million was payable to the Trust from the director. This payable will be netted against the settlement of the adjustment payment for the Oklahoma Assets as noted above. At September 30, 2006 no amounts were payable or receivable from the officer.

12. Relationship with JED Oil Inc. ("JED")

On January 1, 2006, the Trust terminated the Technical Services Agreement with JED. The Trust now manages its own management, development, exploitation, operations and general and administrative activities.

On February 1, 2006, the Trust repaid the \$8,000,000 unsecured notes payable to JED that were outstanding at December 31, 2005. During the first quarter of 2006, \$64,000 of interest was charged on the notes.

On September 28, 2006, the Trust terminated the existing farmout, joint services and business principles agreements with JED. Concurrent with the termination of the agreements, the Trust settled all (\$13.1 million) amounts owing to JED (December 31, 2005 - \$15.2 million).