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November 9, 2006

Securities and Exchange Commission
100 F Street N.E.
Washington, D.C. 20549
USA

SEC MAIL PROCESSING RECEIVED
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WASH. D.C. 213 SECTION

Dear Sir or Madam:

SUPPL

Re: Rule 12g3-2(b) Submission
Commission File No. 82-34957

Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934, as amended, Thunder Energy Trust hereby furnishes to the Commission the following:

1. Press Release dated November 9, 2006.

Yours truly

Sheila Hearnden
Executive Assistant

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THUNDER ENERGY TRUST | NEWS RELEASE | THY.UN

Thunder Announces 12-cent Distribution, Third Quarter 2006 Results and 2006 Operational Update

Calgary, Alberta. November 9, 2006 - Thunder Energy Trust (TSX: THY.UN) today released financial and operational results for the three months and nine months ended September 30, 2006. As the Trust was formed on July 7, 2005, substantially all of the comparative 2005 third quarter results are for the Trust's operations. However, for the nine-month period, in accordance with Canadian generally accepted accounting principles ("GAAP"), comparative year to date 2005 results are for the Trust and its predecessor, Thunder Energy Inc., and therefore are not directly comparable with the 2006 results for the Trust.

Distributions

Thunder Energy Trust has declared a distribution of 12 cents per trust unit to be paid on December 15, 2006, in respect of November production, for unitholders of record on November 22, 2006. The ex distribution date is November 20, 2006.

Declared monthly distributions for the third quarter totalled $0.36 per unit, down from $0.45 per unit for third quarter 2005 with the decline due to lower commodity prices. For the nine months of 2006, distributions totalled $1.20 per unit. Declared distributions totalled $17.4 million for the third quarter, representing a payout ratio of 93% before the Trust's Distribution Reinvestment Program (DRIP) and 49% after taking into account the DRIP. Year to date, declared distributions totalled $56.2 million with a payout ratio of 93% before the DRIP, 51% after the DRIP. Cumulative distributions since the Trust's inception to September 30, 2006 were $2.10 per unit.

Financial

Quarterly funds from operations totalled $18.8 million ($0.39 per unit basic, $0.36 per unit diluted) compared with $35.0 million in third quarter 2005 ($0.79 per unit basic and diluted). The quarter over quarter decline reflects a 37% decrease in natural gas prices at the wellhead to an average $5.79/mcf, a 2% reduction in average oil and NGL prices at the wellhead to $68.51/bbl and a 20% decline in average production.

For the nine months, funds from operations totalled $60.5 million ($1.28 per unit basic; $1.16 per unit diluted). The decline in the average natural gas price was less severe for the nine months at 19% with the Trust averaging $6.36/mcf, offset by a 7% increase in average production to 9,511 boe/d and 3% growth in the average oil and NGL price at the wellhead to $64.18/bbl.

The Trust recorded net income of $8.3 million for the quarter ($0.17 per unit basic and diluted) versus $7.7 million in third quarter 2005 ($0.18 per unit basic and $0.17 per unit diluted). For the nine months, net income totalled $30.7 million ($0.65 per unit basic and $0.60 per unit diluted), a substantial increase from the $15.6 million recorded for the nine months of 2005. The increase is attributable to, among other factors, future tax recoveries due to the federal and provincial governments enacting significant future tax deductions in second quarter 2006.

Production

Production for the third quarter 2006 averaged 9,229 boe/d, 62% of which was natural gas. Production was within 1.0% of second quarter volumes of 9,307 boe/d. Gas volumes averaged 34.2 mmcf/d versus 34.0 mmcf/d in Q2 2006; average oil and NGL volumes of 3,532 bbls/d were down 3% from 3,640 bbls/d in second quarter 2006. Approximately 60% of the behind pipe volumes of 1,930 boe/d reported at the end of June, were brought on stream in late August and September. At September end, behind pipe volumes were estimated at 740 boe/d.

Hedging

Thunder's hedging policy is designed to mitigate downside commodity price risk. In third quarter 2006, hedging activity resulted in a realized loss of $0.7 million and an unrealized gain of $8.2 million. For the nine months, hedging resulted in a realized loss of $1.9 million and an unrealized gain of $6.0 million.

A complete hedging summary is included in the attached Management Discussion and Analysis (MD&A).

Q3 2006 Activity

Thunder Trust drilled 24 wells (18.5 net) in the third quarter comprising 14 gas wells (13.5 net), four oil wells (1.4 net) and six (3.6 net) dry and abandoned wells (D&A). Drilling and completion results for Q3 2006 yielded an 80.5% success rate as detailed below. Capital expenditures for the third quarter totalled $20.7 million.

	Oil		Gas		D&A		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Central Alberta								
Fenn-Big Valley	0	0.0	12	12.0	6	3.6	18	15.6
Rosalind	0	0.0	1	1.0	0	0.0	1	1.0
Matziwin	1	1.0	0	0.0	0	0.0	1	1.0
Manola	0	0.0	1	0.5	0	0.0	1	0.5
West Alberta								
Sylvan Lake	1	0.3	0	0.0		0.0	1	0.3
Northern Alberta	2	0.1	0	0.0	0	0.0	2	0.1
Totals	**4**	**1.4**	**14**	**13.5**	**6**	**3.6**	**24**	**18.5**
Success	**80.5%**							

Operational Update

Central Alberta

Fenn-Big Valley: The majority of Thunder's Q3 2006 drilling activity was in the Fenn-Big Valley area, with 18 wells (15.6 net) drilled at a success rate of 77%. This brings the year to date total to 24 wells (20.0 net). All but 3 (3.0 net) wells from the 2005 and 2006 program are now on production and will undergo a rigorous post-investment appraisal in light of lower commodity process. Of the wells drilled in 2006, 58% were economic successes, however, based on the cost sharing agreement detailed below, success rises to 70% on a capital adjusted basis.

Under the agreement with Ember Resources Inc. (Ember), joint drilling is targeting Thunder's 100%-owned conventional Belly River sand potential and Ember's 100%-owned coalbed methane (CBM) resource potential in a single well bore. This cost sharing enhances the economics of the Belly River development program in the Fenn-Big Valley area. Drilling costs to the base of the Belly River sands are shared 60% by Thunder and 40% by Ember. Thunder pays approximately 40% of major facility costs and 100% of Belly River completion costs; Ember pays 100% of the CBM completion costs. Projected capital cost savings pursuant to this strategic alliance are approximately 30%. This alliance provides the opportunity to fully exploit the Belly River sand potential on a higher drilling density basis.

Approximately half of the area's behind pipe volumes of 640 boe/d at the end of June 2006 were brought on stream in the third quarter. At September 30, 2006, an estimated 300 boe/d remained behind pipe at Fenn. Thunder participated in the expansion of a non-operated compression facility and, although construction was delayed, start up was initiated in early October 2006.

Rosalind: One well (1.0 net) was drilled at Rosalind in Q3 2006, based on interpretation of Thunder's proprietary 3-D seismic. Two separate Mannville zones were encountered which tested a total of 4.3 mmcf/d (4.3 net). Current production from this well is 1.2 mmcf/d (1.2 net) and flows through Thunder 100% owned and operated facilities. Year to date drilling at Rosalind totalled seven wells (6.0 net) with an associated success rate of 83%.

Matziwin: One oil well (1.0 net) was drilled in Matziwin, which tested at 240 boe/d (240 net) from the Lower Mannville zone. The well is tied in and currently producing to Thunder-owned facilities.

Manola: One gas well (0.5 net) was drilled at Manola in Q3 2006, which tested at approximately 0.8 mmcf/d (0.40 net) from an Upper Manville sandstone. The well is currently awaiting tie in. Two additional wells (1.0 net) are scheduled for drilling in the fourth quarter based on new 3-D seismic shot in Q1 2006.

West Alberta

Greater Sylvan Lake: One well (0.25 net) at Sylvan Lake was drilled at 12-36-38-4W5 in the third quarter with the Trust's strategic partner, Alberta Clipper Resources Inc. The well encountered 112 feet of net oil pay in the Leduc Formation averaging 9% porosity. During a five-day testing period, the well flowed at restricted rates averaging 1,775 boe/d (444 net) from three perforation intervals in the Leduc formation. At the end of the quarter, behind pipe volumes for this well were 220 boe/d net to Thunder. This well is now tied in to Thunder-operated facilities, and is currently flowing at a restricted rate pending facility optimization.

Thunder is currently drilling one (0.5 net) additional well in the Sylvan Lake area, and another two wells (0.7 net) are scheduled prior to year end. In addition to the fourth quarter drills, the Trust carries an inventory of 11 (4.6 net) potential locations targeting Leduc reefs.

Foothills-Whiskey Creek

To optimize flowing conditions for the Whiskey Creek area, additional compression is required at Imperial Oil's Quirk Creek gas plant. Although originally scheduled for installation in the fourth quarter 2006, the operator has now delayed the on-stream date for this compressor to second quarter 2007.

Land

Year to date, the Trust acquired 5,899 net acres for a total of $3.1 million, resulting in an average cost of $520 per acre ($1,285 per hectare). Primary focus areas for mineral land purchases have been Sylvan Lake, Rosalind and Manola. Sylvan Lake accounted for 3,760 net acres (approximately 64%), which were acquired in the third quarter for $2.3 million. All lands purchased at Sylvan Lake and Rosalind, and the majority of lands purchased in the Manola area, are covered by the Trust's extensive 3-D seismic database.

The Trust's net undeveloped mineral lands at September 30, 2006 totalled 154,000 net acres.

2006 Outlook

Full year 2006 production is now expected to average approximately 9,500 boe/d, reduced from previous guidance of 9,900 to 10,100 boe/d. The reduction is primarily driven from delays in facility on-stream dates at Thunder's Fenn Big Valley and Whiskey Creek areas, plus delays in facility optimization required in the Greater Sylvan Lake area to handle additional volumes and NGL production.

Capital spending for the full year of 2006 is expected to be approximately $75.0 million, up from the previous guidance of $65.0 million, largely due to land purchases, facility upgrades, and incremental drilling costs in the Sylvan Lake area.

"Our location inventory continues to be one of well defined and well balanced development, and low risk exploration, especially in the Sylvan Lake and Central areas of Alberta. Our geological assessment is working extremely well with our 3-D seismic models and has been tangibly confirmed by the last 12 drills, 10 of which are currently producing. The Trust's four-year drilling inventory continues to expand and gravitate to much higher quality targets," said Stuart Keck, President & CEO.

At the end of the third quarter, Thunder's opportunity base included:

- Almost four years of defined drilling inventory;
- Over 21 townships (756 square miles) of 3-D seismic yielding significant drilling success;
- Strategic Partnerships in which tangible benefits are now being realized;
- Undeveloped land holdings of approximately 154,000 net acres at September 30, 2006.
- Estimated tax pools at September 30, 2006 of $300 million.

Subsequent Event

On October 31, 2006, the federal government announced its intention to change the way energy trusts and certain income funds are taxed, which would take effect January 1, 2011. A detailed draft of the proposed legislation has not been provided to the Trust at this time and therefore it is uncertain what impact the legislative changes will have on the Trust and its unitholders. If the proposed changes are enacted, a tax will be applied at the trust level on distributions at rates of tax comparable to the combined federal and provincial corporate tax, estimated at 31.5%. Under this tax regime, distributions would be treated as dividends to unitholders.

For further information please contact:

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Forward-looking Statements

This press release contains forward-looking statements. More particularly, this press release contains statements concerning the Trust's volumes of oil and natural gas that are currently behind pipe and planned exploration and development activities, planned capital expenditures and anticipated average daily production for 2006.

The forward-looking statements are based on certain key expectations and assumptions made by the Trust, including expectations and assumptions concerning prevailing commodity prices and exchange rates, availability and cost of labor and services, the timing of receipt of regulatory approvals, the performance of existing wells, the success obtained in drilling new wells and the performance of new wells and the sufficiency of budgeted capital expenditures in carrying out the Trust's planned activities.

Although the Trust believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Trust can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. These risks are set out in more detail in the Trust's annual information form for the year ended December 31, 2005, which can be accessed at www.sedar.com.

Note: Boe means barrel of oil equivalent on the basis of 1 boe to 6,000 cubic feet of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6,000 cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner.

HIGHLIGHTS

Financial *($000s, except per share data)*		Three Months Ended September 30 2006	2005	% Change	Nine Months Ended September 30 2006	2005	% Change
Petroleum and natural gas sales		**41,352**	65,866	(37)	**129,098**	127,945	1
Funds from operations[1]		**18,777**	35,037	(46)	**60,484**	70,804	(15)
per unit[2]	- basic *($)*	**0.39**	0.79	(51)	**1.28**	1.65	(22)
	- diluted *($)*	**0.36**	0.79	(54)	**1.16**	1.59	(27)
Net income		**8,260**	7,718	7	**30,729**	15,582	97
per unit[2]	- basic *($)*	**0.17**	0.18	(6)	**0.65**	0.36	81
	- diluted *($)*	**0.17**	0.17	-	**0.60**	0.35	71
Capital expenditures		**20,729**	21,228	(2)	**60,442**	63,938	(5)
Distributions declared		**17,399**	19,114	(9)	**56,187**	19,114	194
Distributions declared per unit *($)*		**0.36**	0.45	(20)	**1.20**	0.45	167
Payout ratio[3] before DRIP		**93%**	55%	69	**93%**	27%	244
Payout ratio[3] after DRIP		**49%**	-	100	**51%**	-	100
Total debt including working capital deficiency		**185,036**	148,432	25	**185,036**	148,432	25
Weighted average units outstanding - basic		**48,643**	44,083	10	**47,395**	43,033	10
Weighted average units outstanding - diluted		**55,847**	44,392	26	**54,469**	44,519	22

Operations	Three Months Ended September 30 2006	2005	% Change	Nine Months Ended September 30 2006	2005	% Change
Daily production						
Natural gas *(mcf/d)*	**34,178**	44,680	(24)	**34,908**	40,301	(13)
Oil and NGL *(bbls/d)*	**3,532**	4,128	(14)	**3,693**	2,165	71
Barrels of oil equivalent *(boe/d)*	**9,229**	11,574	(20)	**9,511**	8,882	7
Average sale price[4]						
Natural gas *($/mcf)*	**5.79**	9.13	(37)	**6.36**	7.84	(19)
Oil and NGL *($/bbl)*	**68.51**	69.90	(2)	**64.18**	62.51	3
Wells drilled - gross (net)						
Gas	**14 (13.5)**	16 (10.8)		**37 (25.1)**	33 (23.6)	
Oil	**4 (1.4)**	2 (1.0)		**11 (6.2)**	10 (8.0)	
Dry	**6 (3.6)**	5 (2.7)		**12 (7.2)**	6 (3.7)	
Total	**24 (18.5)**	23 (14.5)		**60 (38.5)**	49 (35.3)	

Barrels of oil equivalent are reported with a 6:1 conversion with six mcf = one barrel

[1]Non-GAAP financial measures are identified and defined in the Management's Discussion and Analysis.

[2]The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after July 7, 2005 as well as the common shares of Thunder Energy Inc. issued prior to conversion on July 7, 2005.

[3]The payout ratio is calculated using distributions declared divided by funds from operations.

[4]Average sale price at the wellhead before hedging gain or loss.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion is management's analysis of Thunder Energy Trust's ("Thunder" or the "Trust") operating and financial data for the quarter ended September 30, 2006, as well as their estimate of future operating and financial performance based on information currently available. It should be read in conjunction with the unaudited interim consolidated financial statements of the Trust for the three and nine months ended September 30, 2006 and the audited consolidated financial statements and notes for the year ended December 31, 2005. These financial statements and additional information about the Trust are available on SEDAR at www.sedar.com. The Management's Discussion and Analysis ("MD&A") and consolidated financial statements of the Trust have been prepared on a continuity of interest basis which recognizes the Trust as the successor to Thunder Energy Inc. ("Thunder Energy"). Accordingly, the MD&A and consolidated financial statements for periods prior to July 7, 2005 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Thunder Energy. As a result, certain prior period information may not be directly comparable. The MD&A was prepared as of November 6, 2006.

Basis of Presentation *- The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.*

Non-GAAP Measurements *- Management uses funds from operations (cash provided by operating activities before changes in non-cash working capital and settlement of asset retirement obligations) to analyze operating performance and leverage. The term distributable cash is used to present the amount of cash that the Trust distributes to unitholders. The payout ratio is used to present the amount of cash as a percentage of the Trust's funds from operations which are distributed before and after the distribution reinvestment program ("DRIP"). Distributable cash, funds from operations and payout ratio presented have no standardized meaning prescribed by GAAP; therefore, they may not be comparable with the calculation of similar measures for other entities. Distributable cash, funds from operations and the payout ratio as presented are not intended as alternates to, or to be more meaningful than, GAAP performance measures such as net income. The reconciliation between net income and funds from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust also presents funds from operations per unit whereby per unit amounts are calculated using weighted average units outstanding consistent with the calculation of earnings per unit. Distributable cash is calculated using funds from operations less funds withheld for capital expenditures. Payout ratio is calculated as funds from operations divided by declared distributions before and after DRIP. The Trust considers funds from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt, and to fund future capital investments. Distributable cash, funds from operations and payout ratio are used by research analysts to value and compare oil and gas trusts and are frequently included in published third-party research when providing investment recommendations.*

BOE Presentation *- The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. The boe conversion ratio used by the Trust of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.*

Forward-looking Statements *- Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. Forward-looking statements included in the MD&A concern anticipated cash flow to fund distributions and capital expenditures.*

Forward-looking statements and information are based on the Trust's current beliefs as well as assumptions made by and information currently available to the Trust concerning anticipated financial performance, business prospects, strategies and regulatory developments. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third-party operators; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; compliance with environmental laws and regulations; changes in tax laws; the failure to qualify as a mutual fund trust; and the Trust's ability to access external sources of debt and equity capital. Further information regarding these factors may be found in the Trust's annual report for the year ended December 31, 2005 under the headings "Critical Accounting Estimates" and "Risks and Uncertainties" in the MD&A.

The Trust cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to the Trust, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. The forward-looking statements and information contained in this MD&A are as of the date hereof and the Trust undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Corporate Reorganization

Effective July 7, 2005, Thunder Energy, Mustang Resources Inc. ("Mustang") and Forte Resources Inc. ("Forte") entered into a business combination resulting in the conversion into an energy trust through a Plan of Arrangement. The reorganization resulted in the shareholders of Thunder Energy receiving Trust units in the new oil and natural gas energy trust, Thunder Energy Trust, and common shares in two new publicly-listed companies: Ember Resources Inc. ("Ember"), a coalbed methane company, and Alberta Clipper Energy Inc. ("Clipper") an exploration and production company. An additional exploration and production company was created, Valiant Energy Inc. ("Valiant"), which owns certain Forte exploration assets and undeveloped lands.

Shareholders of Thunder Energy received common shares of Ember and Clipper and at their election, either units of the Trust or exchangeable shares which may be exchanged into units of the Trust. Specifically, shareholders of the respective companies, after the consolidation of shares, received:

For each Thunder Energy common share owned:

(a) 0.5 Trust units or exchangeable shares
(b) 0.3333 common shares of Clipper
(c) 0.3333 common shares of Ember

For each Mustang common share owned:

(a) 0.55 Trust units or exchangeable shares
(b) 0.3666 common shares of Clipper
(c) 0.0833 common shares of Ember

For each Forte common share owned:

(a) 0.175 Trust units or exchangeable shares
(b) 0.3333 common shares of Valiant

Results of Operations

Gross oil and gas revenues decreased 37% to $41.4 million for the three months ended September 30, 2006 compared with the same period in 2005 and increased 1% to $129.1 million for the nine months ended September 30, 2006. The decline in third quarter revenues was mainly due to lower natural gas prices and lower production volumes. Year-to-date revenues remained steady as declining natural gas prices during the year were offset by higher production for the nine months.

In the third quarter of 2006, natural gas revenues decreased 50% from the same period in 2005 due to a 37% decrease in Thunder's average price at the wellhead and a 24% decline in gas production offset by a realized hedging gain of $0.4 million. Oil and NGL revenues were down 20% in the third quarter from 2005 due to a 2% decrease in the average price at the wellhead and a 14% decline in production offset by a $1.0 million realized hedging loss.

For the first nine months natural gas revenues decreased 29% from 2005 due to a 19% decline in Thunder's average natural gas price at the wellhead and a 13% production decrease, offset by a realized hedging gain of $0.7 million. Oil and NGL revenues increased 68% due to a 3% rise in Thunder's average price at the wellhead and a 71% increase in oil and NGL production offset by a realized hedging loss of $2.6 million.

In 2006 the Trust entered into financial contracts to mitigate the effect of commodity price fluctuations. The above noted hedging gains and losses relate to contracts to hedge 15,000 GJ/d of natural gas and 2,400 bbls/d of crude oil. The net effect of these contracts was a realized loss of $0.7 million and an unrealized gain of $8.2 million for the third quarter and a realized loss of $1.9 million and an unrealized gain of $6.0 million for the year to date.

Oil and Gas Revenues *($000s)*

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Gross revenues	**41,352**	65,866	**129,098**	127,945
Transportation expenses	**(885)**	(1,982)	**(3,796)**	(4,800)
Net revenues	**40,467**	63,884	**125,302**	123,145
Realized net loss on commodity contracts	**(660)**	-	**(1,886)**	-
Net revenues after realized hedging loss	**39,807**	63,884	**123,416**	123,145
Unrealized net gain on commodity contracts	**8,244**	-	**5,985**	-
Net revenues after realized and unrealized hedging gain/loss	**48,051**	63,884	**129,401**	123,145

Oil and Gas Revenues
($000s, net of transportation expenses and realized hedging gain/loss)

	Natural Gas	Crude Oil and NGL	Total
Three months ended September 30, 2005	**37,338**	**26,546**	**63,884**
Effect of change in product prices	(10,313)	(451)	(10,764)
Effect of change in sales volumes	(8,821)	(3,832)	(12,653)
Effect of realized gain (loss) on commodity contracts	390	(1,050)	(660)
Three months ended September 30, 2006	**18,594**	**21,213**	**39,807**
Nine months ended September 30, 2005	**86,189**	**36,956**	**123,145**
Effect of change in product prices	(14,047)	1,687	(12,360)
Effect of change in sales volumes	(11,542)	26,059	14,517
Effect of realized gain (loss) on commodity contracts	705	(2,591)	(1,886)
Nine months ended September 30, 2006	**61,305**	**62,111**	**123,416**

Production

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Crude oil *(bbls/d)*	**3,146**	3,833	**3,278**	1,960
NGL *(bbls/d)*	**386**	295	**415**	205
Total crude oil and NGL *(bbls/d)*	**3,532**	4,128	**3,693**	2,165
Natural gas *(mcf/d)*	**34,178**	44,680	**34,908**	40,301
Total *(boe/d)*	**9,229**	11,574	**9,511**	8,882
Percentage gas *(%)*	**62**	64	**61**	76

Average Commodity Prices

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Natural gas *($/mcf)*				
NYMEX *($US/mmbtu)*	6.53	8.17	7.48	7.15
AECO Daily *($/mmbtu)*	5.65	9.37	6.40	7.88
Thunder price before hedging and transportation	**5.98**	9.50	**6.60**	8.17
Transportation	(0.19)	(0.37)	(0.24)	(0.33)
Thunder price at the wellhead	**5.79**	9.13	**6.36**	7.84
Realized gain on commodity contracts	0.12	-	0.07	-
Thunder price after hedging	**5.91**	9.13	**6.43**	7.84
Crude oil *($/bbl)*				
WTI *($US/bbl)*	70.48	63.19	68.22	55.40
Edmonton posted	79.08	76.51	75.53	67.91
Thunder price before hedging and transportation	**69.36**	71.13	**65.68**	64.56
Transportation	(0.85)	(1.23)	(1.50)	(2.05)
Thunder price at the wellhead	**68.51**	69.90	**64.18**	62.51
Realized loss on commodity contracts	(3.23)	-	(2.57)	-
Thunder price after hedging	**65.28**	69.90	**61.61**	62.51
Cdn/US $ average exchange rate	**1.121**	1.202	**1.133**	1.220

Transportation expenses were down 55% to $0.9 million compared with third quarter 2005 and 21% to $3.8 million for the first nine months of 2006. The Trust's transportation expenses per barrel for crude oil have not increased proportionately with the rise in production as the majority of crude oil production acquired from Mustang and Forte in 2005 is pipeline connected.

Financial Instruments

The Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contracts	Volume GJ/d	Pricing Point	Strike Price per GJ	Term
Costless Collar	15,000	AECO	Cdn$6.00 to Cdn$6.50	April 1/06 to Oct 31/06
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$9.40	Nov 1/06 to March 31/07
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$10.00	Nov 1/06 to March 31/07

Oil Contracts	Volume bbls/d	Pricing Point	Strike Price per bbl	Term
Costless Collar	800	WTI NYMEX	US$61.00 to US$72.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$73.05	Jan 1/07 to Mar 31/07
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to Mar 31/07

The net effect of these contracts was a realized loss of $0.7 million and an unrealized gain of $8.2 million during the three months ended September 30, 2006 and a realized loss of $1.9 million and unrealized gain of $6.0 million during the nine month period.

Subsequent to September 30, 2006, the Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contract	Volume GJ/d	Pricing Point	Strike Price per GJ	Term
Costless Collar	10,000	AECO	Cdn$6.50 to Cdn$8.10	April 1/07 to Oct 31/07

Oil Contracts	Volume bbls/d	Pricing Point	Strike Price per bbl	Term
Costless Collar	800	WTI NYMEX	US$60.00 to US$70.50	April 1/07 to June 30/07
Costless Collar	800	WTI NYMEX	US$60.00 to US$72.50	July 1/07 to Sept 30/07

Royalties decreased to $7.6 million in the third quarter of 2006 and to $23.1 million for the first nine months of the year, decreases of 41% and 7%, respectively over the corresponding prior periods in 2005. Royalties as a percentage of net revenue decreased to 18.8% from 20.2% in the third quarter 2005, and increased to 18.4% from 17.5% for the nine-month period. The third quarter decline in royalties from 2005 was due to lower revenue compared to 2005. The increase in royalties during the first nine months of 2006 was due to higher revenue in 2006 and a gas cost allowance refund in the second quarter of 2005.

Royalties *($000s)*

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Crown	**5,423**	10,539	**16,942**	17,275
Freehold and other	**2,293**	2,483	**6,546**	4,697
Gross royalties	**7,716**	13,022	**23,488**	21,972
ARTC	**(125)**	(125)	**(375)**	(366)
Net royalties	**7,591**	12,897	**23,113**	21,606

Royalty Rates *(as a % of net revenues)*

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Crown	**13.4**	16.5	**13.5**	14.0
Freehold and other	**5.7**	3.9	**5.2**	3.8
Gross royalties	**19.1**	20.4	**18.7**	17.8
ARTC	**(0.3)**	(0.2)	**(0.3)**	(0.3)
Net royalties	**18.8**	20.2	**18.4**	17.5

Operating costs increased 4% from the third quarter 2005 to $9.4 million and 39% to $27.5 million in the first nine months of 2006. In addition to the general rise in costs for services and supplies in the oil industry and high fuel and power costs, the increase was due to the acquisitions of Mustang and Forte and the transition into a Trust. The acquisition of Forte increased the Trust's operations in northeast B.C. and northern Alberta where operating costs are generally higher compared with central Alberta. In the current commodity price environment, low-rate, high cost wells that would otherwise be unprofitable continue to contribute to the overall production base.

Operating Costs

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Operating costs *($000s)*	**9,426**	9,059	**27,462**	19,827
Per boe *($)*	**11.10**	8.51	**10.58**	8.18

Gross general and administrative expenses (G&A) increased 30% to $3.5 million for the third quarter of 2006 and 50% to $10.1 million for the nine months ended September 30, 2006 compared to the same periods in 2005 due to increased salaries and benefits and office space as a result of the transition into a Trust. Net G&A was $2.27 per boe and $2.18 per boe for the three and nine months ended September 30, 2006 respectively. The increases over the corresponding prior periods were due to the increased size of the Trust as well as several budgeted, one-time costs such as audit and tax services, annual filing costs and consulting services. Also included in G&A are costs relating to documenting internal controls to meet regulatory requirements. For the third quarter these costs totaled $0.1 million or $0.11/boe.

G&A Expenses

G&A Expenses *($000s)*	Three months ended September 30 **2006**	2005	Nine months ended September 30 **2006**	2005
Gross G&A expenses	**3,538**	2,719	**10,083**	6,710
Capitalized G&A	**(1,227)**	(405)	**(2,885)**	(1,214)
Overhead recoveries				
Capital	**(144)**	(158)	**(699)**	(1,083)
Operating	**(238)**	(565)	**(837)**	(1,094)
Net G&A expenses	**1,929**	1,591	**5,662**	3,319
Non-recurring retention & severance	**-**	3,300	**-**	3,300
Net G&A & non-recurring expense	**1,929**	4,891	**5,662**	6,619
G&A Expenses *($/boe)*				
Gross G&A expenses	**4.17**	2.55	**3.88**	2.77
Capitalized G&A	**(1.45)**	(0.38)	**(1.11)**	(0.50)
Overhead recoveries				
Capital	**(0.17)**	(0.15)	**(0.27)**	(0.45)
Operating	**(0.28)**	(0.53)	**(0.32)**	(0.45)
Net G&A expenses	**2.27**	1.49	**2.18**	1.37
Non-recurring retention & severance	**-**	3.10	**-**	1.36
Net G&A & non-recurring expense	**2.27**	4.59	**2.18**	2.73

Financial charges are comprised of bank debt interest, convertible debenture interest, amortization of deferred financing costs and accretion of convertible debenture liability. Financial charges have increased by 78% to $2.9 million for the quarter and 101% to $7.0 million for the nine months ended September 30, 2006 compared to the same periods in 2005. Financial charges have increased due to increased interest rates and higher levels of debt due to lower commodity prices and production. A reconciliation of these charges is as follows:

Financial charges *($000s)*	Three Months Ended September 30 **2006**	2005	Nine Months Ended September 30 **2006**	2005
Bank debt interest	**1,276**	1,625	**3,883**	3,501
Convertible debenture interest	**1,360**	-	**2,654**	-
Amortization of deferred financing costs	**180**	-	**348**	-
Accretion of convertible debenture liability	**70**	-	**137**	-
Total financial charges	**2,886**	1,625	**7,022**	3,501

Bank debt interest for the quarter decreased 21% from 2005 due to a decrease in the average bank debt outstanding offset by a higher effective interest rate. The decrease in the average bank debt was due to the issuance of convertible debentures during the second quarter of 2006. For the first nine months of 2006 interest expense increased 11% from 2005 due to a higher effective interest rate offset by a lower average bank debt outstanding.

Bank Debt

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Average bank debt outstanding *($000s)*	**96,651**	144,397	**106,140**	117,500
Effective annualized interest rate for the period *(%)*	**5.2**	4.5	**4.9**	4.0

Convertible debenture interest was $1.4 million for the third quarter of 2006 and $2.7 million year to date. Thunder issued convertible debentures of $75.0 million during the second quarter of 2006. The net proceeds of $71.6 million were used to repay bank debt.

Depletion, depreciation and accretion expense (DD&A) increased to $22.9 million in the third quarter and $69.8 million in the first nine months of 2006. The increases reflect the rise in general industry costs and the reduction in proved reserves at year-end 2005. A ceiling test was performed at September 30, 2006 and it was determined that there was no impairment to the carrying value of the Trust's unamortized capitalized costs.

DD&A Expense

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
DD&A expense *($000s)*	**22,911**	22,650	**69,788**	45,104
Per boe *($)*	**26.98**	21.27	**26.88**	18.60

Unit-based compensation expense was $0.5 million in the third quarter of 2006 and $1.3 million for the first nine months of 2006, down from $6.1 million and $7.9 million in the corresponding periods of 2005 due to the corporate reorganization in the prior year. The Trust's unit-based compensation is determined based on the intrinsic value of the Trust units at each period end.

Provision for Income Taxes

The Trust is a taxable entity under the Tax Act (Canada), but is taxable only on income that is not distributed or distributable to the unitholders. To the extent that cash distributions represent taxable distributions to unitholders, the distributions will reduce the Trust's future income tax expense. The Trust had a future income tax recovery of $4.9 million for the third quarter and $35.8 million for the nine months ended September 30, 2006 primarily due to the estimated taxability of distributions as well as future tax rate reductions enacted by the federal and provincial governments during the second quarter.

In 2006 the federal budget eliminated the large corporations tax effective for the 2006 taxation year. The Trust is still required to pay Saskatchewan capital tax.

Funds from operations for the third quarter decreased 46% from the same period in 2005 to $18.8 million due to decreased production, lower natural gas prices and higher operating costs and G&A expenses. For the nine months of 2006 funds from operations decreased 15% from 2005 to $60.5 million due to lower natural gas prices and a decline in natural gas production from the prior year along with higher operating and G&A expenses.

Funds from Operations

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Funds from operations *($000s)*	**18,777**	35,037	**60,484**	70,804
Per unit - basic *($)*	**0.39**	0.79	**1.28**	1.65
- diluted *($)*	**0.36**	0.79	**1.16**	1.59

Net income increased 7% in the third quarter 2006 to $8.3 million and 97% to $30.7 million for the nine months ended September 30 compared with the same periods in 2005. The increases are attributable to, amongst other things, future income tax recoveries offset by higher DD&A expenses.

Net Income

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Net income *($000s)*	**8,260**	7,718	**30,729**	15,582
Per unit - basic *($)*	**0.17**	0.18	**0.65**	0.36
- diluted *($)*	**0.17**	0.17	**0.60**	0.35

Asset retirement obligations are accrued by the Trust resulting from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust periodically reviews the assumptions used in its asset retirement obligation calculation. In the current period, a revision was made to the liability to reflect an increase in the inflation rate from 1.5% to 2.0%. A reconciliation of the asset retirement obligations is provided below:

Asset Retirement Obligations *($000s)*

	Nine Months Ended September 30 2006	Year ended December 31 2005
Balance, beginning of period	**$ 24,774**	$ 13,417
Liabilities incurred in the period	**703**	1,758
Liabilities assumed due to business combination - Forte	**-**	7,596
Liabilities assumed due to business combination - Mustang	**-**	5,019
Revision	**1,513**	(135)
Liabilities released due to dispositions	**-**	(3,328)
Liabilities settled in the period	**(1,652)**	(1,306)
Accretion expense	**1,904**	1,753
Balance, end of period	**$ 27,242**	$ 24,774

Capital and Liquidity

Capital expenditures for the third quarter totaled $20.7 million and $60.4 million for the year to date. Drilling, completion, equipping and tie-in costs totalled $45.6 million for the nine month period for the drilling of 37 gas wells (25.1 net), 11 oil wells (6.2 net), and 12 dry holes (7.2 net). The Trust's drilling success ratio was 81%. The following table breaks out the capital expenditures by category:

Capital Expenditures Summary *($000s)*

	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Land and rentals	**3,137**	357	**5,062**	2,659
Seismic	**999**	206	**2,880**	4,243
Drilling and completions	**9,597**	10,613	**35,011**	34,855
Well equipping and tie-in	**5,169**	5,507	**10,553**	16,021
Facilities and gas gathering	**660**	4,068	**1,354**	4,890
Other, including capitalized G&A	**1,167**	477	**5,582**	1,270
Total capital expenditures	**20,729**	21,228	**60,442**	63,938

Liquidity

For the nine months ended September 30, 2006, capital expenditures of $60.4 million, the settlement of asset retirement obligations of $1.7 million, a combined decrease to long-term debt, unit issue costs and working capital of $38.0 million and cash distributions, net of the distribution reinvestment plan ("DRIP"), of $31.9 million were funded by funds from operations of $60.5 million and net proceeds from convertible debentures of $71.6 million.

The Trust has a $160.0 million credit facility with a syndicate of chartered banks consisting of a $145.0 million revolving term credit facility and a $15.0 million operating credit facility. The credit facilities are available on a revolving basis for a period of at least 364 days until April 30, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a two-year term, payable in quarterly payments in the second year. The credit facilities are collateralized by the Trust's assets and are subject to semi-annual review at which time the lenders may re-determine the borrowing base. The next scheduled semi-annual review is scheduled for April 30, 2007.

Management anticipates that Thunder will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2006 through a combination of cash flow, debt and equity. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Convertible Debentures

On April 5, 2006, the Trust issued $75.0 million principal amount of 7.25% Convertible Unsecured Subordinated Debentures (the "Debentures") for net proceeds of $71.6 million. The Debentures have a conversion price of $11.70 per Trust unit and a maturity date of April 30, 2011. The Debentures pay interest semi-annually in arrears on April 30 and October 31 each year, commencing October 31, 2006. The Debentures will not be redeemable by the Trust prior to April 30, 2009. The Debentures are redeemable by the Trust, on not more than 60 days and not less than 30 days prior notice, at a price of

$1,050 per Debenture after April 30, 2009 and on or before April 30, 2010, and at a price of $1,025 per Debenture after April 30, 2010 and before the maturity date, in each case, plus accrued and unpaid interest thereon, if any. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal and may satisfy its interest obligations by issuing Thunder Energy Trust units. The Debentures are traded on the Toronto Stock Exchange under the trading symbol THY.DB.

The Debentures have been classified as debt net of the fair value of the conversion feature at the date of issue, which has been classified as part of unitholders' equity. The debt portion will accrete up to the principal balance at maturity. Issue costs have been classified under deferred financing costs and are being amortized over the term of the Debentures. If the Debentures are converted into units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to Trust units along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

Convertible Debentures ***($000s)***	**As at September 30, 2006**
Debt portion on April 5, 2006	$ 73,298
Accretion of non-cash interest	137
Debt portion, end of period	73,435
Equity portion	1,702
Total Debentures, end of period	**$ 75,137**

Distributable Cash and Distributions

Management and the Board of Directors monitor the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. Distributions are made at the discretion of the Trust's management and Board of Directors. During the third quarter of 2006, 93% of funds from operations before DRIP were distributed, 49% after DRIP. For the nine months ended September 30, 2006, 93% of funds from operations before DRIP were distributed, 51% after DRIP. Exchangeable shares are convertible into Trust units based on the Exchange Ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. Commodity prices and production volumes are critical variables in determining cash flow and changes in these two items have a material impact on cash flow and distributions.

The amount of distributable cash is calculated in accordance with the Trust's indenture. Distributable cash is not a measure under GAAP and there is no standard measure of distributable cash. Distributable cash, as presented, may not be comparable to similar measures presented by other trusts.

Distributions *($000s)*

	Three months ended September 30, 2006	Nine months ended September 30, 2006
Cash provided by operating activities	28,033	59,824
Settlement of asset retirement obligations	1,262	1,652
Changes in non-cash working capital related to operating activities	(10,518)	(992)
Funds from operations	18,777	60,484
Cash used to fund capital expenditures	(9,757)	(28,549)
Distributable cash	9,020	31,935
Cash distributions declared and payable, including DRIP at September 30, 2006	5,840	5,840
Cash distributions paid in the period	9,020	31,935
Accumulated cash distributions paid and payable	14,860	37,775

Distributions Declared *($000s)*

	Cash distributions	DRIP	Total
Balance December 31, 2005	34,362	4,384	38,746
January distribution	4,501	2,248	6,749
February distribution	4,127	2,705	6,832
March distribution	3,554	3,350	6,904
Balance March 31, 2006	46,544	12,687	59,231
April distribution	3,543	3,428	6,971
May distribution	2,907	2,722	5,629
June distribution	2,987	2,716	5,703
Balance June 30, 2006	55,981	21,553	77,534
July distribution	3,029	2,731	5,760
August distribution	3,004	2,795	5,799
September distribution	3,075	2,765	5,840
Balance September 30, 2006	**65,089**	**29,844**	**94,933**

Distributions per unit

	Three months ended September 30, 2006	Nine months ended September 30, 2006
Cash distributions declared and payable per unit	$0.12	$0.12
Cash distributions declared and paid per unit	$0.24	$1.08
Accumulated cash distributions per unit	$0.36	$1.20

Tax Treatment of Distributions

The Trust has provided to unitholders general comments regarding the taxability of distributions but does not intend to provide legal or tax advice. Trust unitholders, exchangeable shareholders, or potential investors should seek their own legal or tax advice in this regard.

Related Party Transactions

During the three and nine months ended September 30, 2006, the Trust incurred expenditures of $0.2 million and $0.5 million, respectively for general corporate legal fees to a legal firm of which a director is a partner. These legal fees were included in general and administrative expenses, convertible debenture issue costs, property and equipment and unit issue costs. At September 30, 2006, $14,000 was included in accounts payable. The related party transactions were recorded at the exchange amount as services were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.

Subsequent Event

On October 31, 2006 the Government of Canada proposed changes to the tax treatment of income trusts that would take effect in 2011. The Trust has not completed its assessment of the potential implications that these proposed changes might have.

Quarterly Information

The following table is a summary of quarterly results for the last eight quarters relating to the years 2006, 2005 and 2004. Because the consolidated financial statements of the Trust have been prepared on a continuity of interest basis which recognized the Trust as the successor to Thunder Energy, results prior to July 7, 2005 may not be directly comparable to those of the Trust.

Revenue is directly related to fluctuations in commodity prices and production. Declines in natural gas prices in the first nine months of 2006 resulted in lower revenues and distributable cash from the fourth quarter of 2005. Natural gas, oil and NGL production have steadied through the second and third quarters of 2006.

The Trust recorded a write-down of the carrying value of its petroleum and natural gas property and equipment in the fourth quarter of 2005 resulting in a net loss of $25.4 million. The Trust recognized a future tax recovery of $25.0 million in the second quarter of 2006 related to a reduction in future federal and provincial income tax rates as well as the taxability of distributions. This resulted in net income of $18.7 million for the second quarter.

Quarterly Information	2004		2005	
($000s, except per unit data)	Q4	Q1	Q2	Q3
Petroleum and natural gas sales	29,049	29,350	32,729	65,866
Funds from operations	15,525	16,599	19,168	35,037
Per unit *($)*				
Basic	0.61	0.64	0.74	0.79
Diluted	0.60	0.63	0.73	0.79
Net income	1,407	3,243	4,621	7,718
Per unit *($)*				
Basic	0.06	0.13	0.18	0.18
Diluted	0.05	0.12	0.18	0.17
Daily production				
Natural gas *(mcf/d)*	38,827	38,174	37,978	44,680
Oil and NGL *(bbls/d)*	1,307	1,145	1,190	4,128
Barrels of oil equivalent *(boe/d)*	7,778	7,508	7,520	11,574
Average sale price[1]				
Natural gas *($/mcf)*	6.57	6.74	7.41	9.13
Oil and NGL *($/bbl)*	43.24	48.67	49.81	69.90

	2005		2006	
	Q4	Q1	Q2	Q3
Petroleum and natural gas sales	67,833	46,242	41,504	**41,352**
Funds from operations	39,587	22,813	18,894	**18,777**
Per unit *($)*				
Basic	0.86	0.50	0.40	**0.39**
Diluted	0.85	0.49	0.36	**0.36**
Net income	(25,433)	3,725	18,744	**8,260**
Per unit *($)*				
Basic	(0.55)	0.08	0.39	**0.17**
Diluted	(0.55)	0.08	0.36	**0.17**
Daily production				
Natural gas *(mcf/d)*	40,489	36,572	34,001	**34,178**
Oil and NGL *(bbls/d)*	4,312	3,910	3,640	**3,532**
Barrels of oil equivalent *(boe/d)*	11,060	10,005	9,307	**9,229**
Average sale price[1]				
Natural gas *($/mcf)*	11.11	7.40	5.83	**5.79**
Oil and NGL *($/bbl)*	62.64	57.34	67.21	**68.51**

[1] *Average sale price at the wellhead before hedging gain or loss.*

CONSOLIDATED BALANCE SHEETS
(unaudited)

($000s)	September 30, 2006	December 31, 2005
Assets (Note 4)		
Current		
Accounts receivable	$ 40,446	$ 49,810
Commodity contracts (Note 9)	5,985	-
Prepaid expenses	2,141	1,219
	48,572	51,029
Deferred financing costs (Note 6)	3,078	-
Property and equipment (Note 3)	652,843	658,069
Goodwill	108,292	108,292
	$ 812,785	$ 817,390
Liabilities and Unitholders' Equity		
Current		
Bank indebtedness	$ 6,404	$ 4,409
Accounts payable and accrued liabilities	40,430	57,542
Distributions payable	5,840	6,595
Future income taxes (Note 10)	1,827	-
Unit-based compensation (Note 8)	613	767
	55,114	69,313
Bank debt (Note 4)	105,059	136,359
Convertible debentures (Note 5)	73,435	-
Unit-based compensation (Note 8)	682	528
Asset retirement obligations (Note 7)	27,242	24,774
Future income taxes (Note 10)	109,203	146,876
	370,735	377,850
Unitholders' equity		
Unitholders' capital (Note 8)	437,607	411,341
Equity component of convertible debentures (Note 5)	1,702	-
Contributed surplus	3,025	3,025
Retained earnings (deficit)	(284)	25,174
	442,050	439,540
	$ 812,785	$ 817,390

See accompanying notes

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS (DEFICIT)
(unaudited)

($000s, except per share data)	Three Months Ended September 30 **2006**	Three Months Ended September 30 2005	Nine Months Ended September 30 **2006**	Nine Months Ended September 30 2005
Revenue				
Petroleum and natural gas sales	**$ 41,352**	$ 65,866	**$ 129,098**	$ 127,945
Royalties, net of ARTC	**(7,591)**	(12,897)	**(23,113)**	(21,606)
Transportation expenses	**(885)**	(1,982)	**(3,796)**	(4,800)
Petroleum and natural gas sales, after royalties and transportation	**32,876**	50,987	**102,189**	101,539
Realized net loss on commodity contracts (Note 9)	**(660)**	-	**(1,886)**	-
Unrealized net gain on commodity contracts (Note 9)	**8,244**	-	**5,985**	-
Petroleum and natural gas sales, net	**40,460**	50,987	**106,288**	101,539
Expenses				
Operating	**9,426**	9,059	**27,462**	19,827
General and administrative	**1,929**	4,891	**5,662**	6,619
Financial charges (Note 6)	**2,886**	1,625	**7,022**	3,501
Unit-based compensation (Note 8)	**549**	6,111	**1,301**	7,901
Depletion, depreciation and accretion	**22,911**	22,650	**69,788**	45,104
	37,701	44,336	**111,235**	82,952
Income (loss) before income taxes	**2,759**	6,651	**(4,947)**	18,587
Provision for income taxes (recovery) (Note 10)	**(5,501)**	(1,067)	**(35,676)**	3,005
Net income for the period	**8,260**	7,718	**30,729**	15,582
Accumulated distributions	**(17,399)**	(19,114)	**(94,933)**	(19,114)
Retained earnings (deficit)				
Beginning of period	**8,855**	81,635	**63,920**	73,771
End of period	**$ (284)**	$ 70,239	**$ (284)**	$ 70,239
Units and exchangeable shares outstanding (weighted average) (Note 8)				
Basic	**48,643**	44,083	**47,395**	43,033
Diluted	**55,847**	44,392	**54,469**	44,519
Net income per unit (Note 8)				
Basic	**$ 0.17**	$ 0.18	**$ 0.65**	$ 0.36
Diluted	**$ 0.17**	$ 0.17	**$ 0.60**	$ 0.35

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

($000s)	Three Months Ended September 30 **2006**	Three Months Ended September 30 2005	Nine Months Ended September 30 **2006**	Nine Months Ended September 30 2005
Operating Activities				
Net income for the period	**$ 8,260**	$ 7,718	**$ 30,729**	$ 15,582
Add items not requiring cash:				
Amortization of deferred financing costs (Note 6)	**180**	-	**348**	-
Accretion on convertible debenture liability (Note 6)	**70**	-	**137**	-
Unit-based compensation	**549**	6,111	**1,301**	7,901
Unrealized net gain on commodity contracts	**(8,244)**	-	**(5,985)**	-
Depletion, depreciation and accretion	**22,911**	22,650	**69,788**	45,104
Future income taxes (Note 10)	**(4,949)**	(1,442)	**(35,834)**	2,217
Settlement of asset retirement obligations	**(1,262)**	(432)	**(1,652)**	(801)
Changes in non-cash working capital relating to operating activities (Note 11)	**10,518**	7,254	**992**	(19,488)
Cash provided by operating activities	**28,033**	41,859	**59,824**	50,515
Financing Activities				
Issue of units for cash, net of costs	**(66)**	10,672	**(54)**	11,506
Convertible debenture issue costs	**(20)**	-	**(3,426)**	-
Proceeds on convertible debentures	**-**	-	**75,000**	-
Increase in bank indebtedness	**1,177**	1,846	**1,995**	3,234
Increase (decrease) in bank debt	**17,265**	28,562	**(31,300)**	53,624
Cash distributions	**(9,020)**	(12,695)	**(31,935)**	(12,695)
Cash received on Plan of Arrangement	**-**	10,000	**-**	10,000
Cash provided by financing activities	**9,336**	38,385	**10,280**	65,669
Investing Activities				
Expenditures on property and equipment	**(20,729)**	(21,228)	**(60,442)**	(63,938)
Assumption of working capital deficit on business acquisition	**-**	(49,546)	**-**	(49,546)
Deferred transaction costs	**-**	2,312	**-**	-
Changes in non-cash working capital related to investing activities (Note 11)	**(16,640)**	(11,782)	**(9,662)**	(2,721)
Cash used in investing activities	**(37,369)**	(80,244)	**(70,104)**	(116,205)
Net change in cash position	**-**	-	**-**	(21)
Cash position - beginning of period	**-**	-	**-**	21
- end of period	**$ -**	$ -	**$ -**	$ -

See accompanying notes

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Basis of Presentation

The interim consolidated financial statements of Thunder 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 of computation as the audited consolidated financial statements for the fiscal year ended December 31, 2005, except that certain disclosures required in annual financial statements have been condensed or omitted. The disclosures below are incremental to those included in the annual consolidated financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes as at and for the year ended December 31, 2005. The results of operations for the three and nine months ended September 30, 2006 may not be indicative of the results for the 2006 fiscal year.

The Trust was established as part of a Plan of Arrangement (the "Arrangement"), which became effective on July 7, 2005. The Arrangement gave effect to the transaction completed with Thunder Energy Inc. ("Thunder Energy"), Mustang Resources Inc. ("Mustang") and Forte Resources Inc. ("Forte") to combine the entities to create a new oil and gas trust, two exploration-focused production companies: Alberta Clipper Energy Inc. ("Clipper") and Valiant Energy Inc. ("Valiant"); and a resource-based coalbed methane company, Ember Resources Inc. ("Ember"). As a result of the combination, shareholders of Thunder Energy received 0.5 Trust units or exchangeable shares of the Trust, 0.3333 common shares of Clipper and 0.3333 common shares of Ember. The Trust accounted for Mustang and Forte as acquisitions under the purchase method of accounting. Certain Mustang assets acquired by Thunder Energy were transferred to Clipper. As the former Thunder Energy shareholders had the majority of the voting control of Clipper, Ember and the Trust (including its subsidiaries), the transfer of assets and liabilities from Thunder Energy to Clipper and Ember was accounted for at Thunder Energy's net book value; the transfer of the Mustang assets to Clipper was at fair value, being Thunder Energy's acquisition cost.

The conversion of Thunder Energy to a trust was accounted for on a continuity of interest basis. Due to the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be directly comparable.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after July 7, 2005 as well as the common shares of Thunder Energy outstanding prior to the conversion on July 7, 2005.

2. Accounting Policies

The Trust is exposed to market risks resulting from fluctuations in commodity prices in the normal course of its business. The Trust may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Trust accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in income as an unrealized gain or loss on commodity contracts. Fair values of financial instruments are determined from third party quotes or valuations provided by independent third parties. Any realized gains or losses on commodity contracts are recognized in income in the period they occur. The Trust may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and it has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy.

3. Property and equipment

Property and equipment *($000s)*	As at September 30, 2006	As at December 31, 2005
Cost	**$ 886,854**	$ 824,196
Accumulated depletion and depreciation	**(234,011)**	(166,127)
Net book value	**$ 652,843**	$ 658,069

During the nine months ended September 30, 2006, the Trust capitalized $2.9 million (2005 - $1.6 million) of general and administrative expenses related to acquisition, exploration and development activities.

At September 30, 2006, costs of $23.1 million (2005 - $16.3 million) related to unproved properties were excluded from the full cost pool.

An impairment test calculation was performed on the Trust's oil and natural gas property interests at September 30, 2006. The estimated undiscounted future net cash flows from proved reserves, using forecast prices, exceeded the carrying amount of the Trust's oil and natural gas property interests and the cost of its unproved properties.

4. Bank Debt

The Trust has a $160.0 million credit facility with a syndicate of chartered banks consisting of a $145.0 million extendible revolving term credit facility and a $15.0 million operating credit facility. The credit facilities are available on a revolving basis for a period of at least 364 days until April 30, 2007, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a two-year term, payable in quarterly payments in the second year. The credit facilities bear interest at the lenders' prime rate, or bankers' acceptance rates plus an applicable margin, based on the debt to cash flow ratio. The credit facilities are collateralized by a $500.0 million demand debenture providing for a fixed and floating charge over the petroleum and natural gas properties and all other assets of the Trust and are subject to semi-annual review, at which time the lenders may re-determine the borrowing base. The effective annualized interest rates for the three and nine months ended September 30, 2006 were 5.2% and 4.9%, respectively (2005 - 4.5% and 4.0%).

5. Convertible Debentures

On April 5, 2006, the Trust issued $75.0 million principal amount of 7.25% Convertible Unsecured Subordinated Debentures (the "Debentures") for net proceeds of $71.6 million. The Debentures have a conversion price of $11.70 per Trust unit and a maturity date of April 30, 2011. The Debentures pay interest semi-annually in arrears on April 30 and October 31 each year, commencing October 31, 2006. The Debentures will not be redeemable by the Trust prior to April 30, 2009. The Debentures are redeemable by the Trust, on not more than 60 days and not less than 30 days prior notice, at a price of $1,050 per Debenture after April 30, 2009 and on or before April 30, 2010, and at a price of $1,025 per Debenture after April 30, 2010 and before the maturity date, in each case, plus accrued and unpaid interest thereon, if any. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal and may satisfy its interest obligations by issuing Thunder Energy Trust units. The Debentures are traded on the Toronto Stock Exchange under the trading symbol THY.DB.

The Debentures have been classified as debt net of the fair value of the conversion feature at the date of issue, which has been classified as part of unitholders' equity. The debt portion will accrete up to the principal balance at maturity. Issue costs have been classified under deferred financing costs and are being amortized over the term of the Debentures. A reconciliation of deferred financing costs is included in Note 6. If the Debentures are converted into units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to Trust units along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

Convertible debentures ***($000s)***	**As at September 30, 2006**
Debt component on April 5, 2006	$ 73,298
Accretion of non-cash interest in the period	137
Debt portion, end of period	73,435
Equity component	1,702
Total Debentures, end of period	**$ 75,137**

6. Financial Charges

During the nine months ended September 30, 2006 and 2005, the Trust incurred interest charges on bank debt and convertible debentures as well as the amortization of deferred financing costs and accretion of convertible debenture liability as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
Financial charges ***($000s)***	**2006**	2005	**2006**	2005
Bank debt interest	**1,276**	1,625	**3,883**	3,501
Convertible debenture interest	**1,360**	-	**2,654**	-
Amortization of deferred financing costs	**180**	-	**348**	-
Accretion of convertible debenture liability	**70**	-	**137**	-
Total financial charges	**2,886**	1,625	**7,022**	3,501

A reconciliation of deferred financing costs is provided as follows:

Deferred financing costs ***($000s)***	**As at September 30, 2006**
Balance, beginning of period	-
Deferred financing costs	3,426
Amortization	(348)
Balance, end of period	**3,078**

7. Asset Retirement Obligations

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $55.0 million which will be incurred up to 2034. The majority of the costs are expected to be incurred between 2010 and 2034. A credit-adjusted risk-free rate of 9.0% and an inflation rate of 2.0% were used to calculate the fair value of the asset retirement obligations. The Trust periodically reviews the assumptions used in its asset retirement obligation calculation. In the current period, a revision was made to the liability to reflect an increase in the inflation rate.

A reconciliation of the asset retirement obligations is provided below:

Asset retirement obligations *($000s)*	Nine Months Ended September 30 **2006**	Year ended December 31 2005
Balance, beginning of period	**$ 24,774**	$ 13,417
Liabilities incurred in the period	**703**	1,758
Liabilities assumed due to business combination - Forte	**-**	7,596
Liabilities assumed due to business combination - Mustang	**-**	5,019
Revision	**1,513**	(135)
Liabilities released due to dispositions	**-**	(3,328)
Liabilities settled in the period	**(1,652)**	(1,306)
Accretion expense	**1,904**	1,753
Balance, end of period	**$ 27,242**	$ 24,774

8. Unitholders' Capital

(a) Trust Units of Thunder Energy Trust

The Trust Indenture provides that an unlimited number of Trust units may be authorized and issued. Each Trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All Trust units are of the same class with equal rights and privileges.

Trust units of Thunder Energy Trust	Number of units *(000s)*	*($000s)*
Balance December 31, 2004	-	$ -
Issued for common shares of Thunder Energy	24,246	174,050
Issued on Forte acquisition (Note 1)	6,475	99,288
Issued on Mustang acquisition (Note1)	9,607	123,810
Reduction of capital, Ember conveyance (Note 1)	-	(19,893)
Reduction of capital, Clipper conveyance (Note 1)	-	(28,047)
Issued for cash on exercise of stock options	1,921	19,332
Stock-based compensation on options	-	7,080
Exchangeable shares converted	1,543	14,713
Unit issue costs, net of tax of $2,353	-	(6,445)
Distribution reinvestment program	175	2,072
Balance December 31, 2005	43,967	$ 385,960
Unit issue costs, net of tax of $4	-	8
Distribution reinvestment program	697	7,265
Exchangeable shares converted	1,364	14,676
Balance March 31, 2006	46,028	$ 407,909
Distribution reinvestment program	1,031	9,500
Issued on exercise of Restricted Trust Units	104	1,301
Exchangeable shares converted	491	5,023
Balance June 30, 2006	47,654	$ 423,733
Distribution reinvestment program	1,005	8,242
Exchangeable shares converted	3	32
Unit issue costs related, net of tax of $16	-	(50)
Balance September 30, 2006	**48,662**	**$ 431,957**

The Trust has a distribution reinvestment program ("DRIP") whereby unitholders can elect to reinvest their distributions back into the Trust and receive additional units rather than receive the cash payment. This accounted for a $25.0 million increase in unitholders' capital for the nine months ended September 30, 2006.

(b) Exchangeable Shares of Thunder Energy Trust

Authorized: unlimited number of exchangeable shares

Exchangeable shares	Number of units *(000s)*	*($000s)*
Balance December 31, 2004	-	$ -
Issued for common shares of Thunder Energy (Note 1)	1,759	13,030
Issued on Forte acquisition (Note 1)	927	14,215
Issued on Mustang acquisition (Note 1)	997	12,849
Exchanged for Trust units	(1,495)	(14,713)
Balance December 31, 2005	2,188	$ 25,381
Exchanged for Trust units	(1,265)	(14,676)
Balance March 31, 2006	923	$ 10,705
Exchanged for Trust units	(433)	(5,023)
Balance June 30, 2006	490	$ 5,682
Exchanged for Trust units	(3)	(32)
Balance September 30, 2006	**487**	**$ 5,650**

Exchangeable shares accrue notional distributions in-kind and are convertible into Trust units at the shareholder's option. Exchangeable shares are non-transferable and are ultimately required to be exchanged for units of the Trust.

The exchangeable shares are not entitled to cash distributions. The Exchange Ratio increases on a monthly basis. The increase in the Exchange Ratio is calculated by multiplying the Thunder Energy Trust distribution per unit by the Exchange Ratio immediately prior to the Record Date and dividing by the weighted average trading price per unit of THY.UN on the TSX for the five trading days preceding the Record Date. A holder of Thunder Energy Inc. exchangeable shares can exchange all or a portion of their holdings into Thunder Energy Trust units, at any time by giving notice to their investment advisor or the Trust Agent. The Exchange Ratio to convert each exchangeable share to a Trust unit was 1.00000 at the time of issuance. Effective September 30, 2006, the Exchange Ratio was 1.19727. If the 0.5 million exchangeable shares outstanding at September 30, 2006 were exchanged at that time, 0.6 million Trust units would have been issued.

(c) Unit-based Compensation

For the three and nine months ended September 30, 2006, the Trust recorded a compensation expense relating to its Trust Unit Incentive Plan of $0.5 million and $1.3 million, respectively (2005 - $6.1 million and $7.9 million). The compensation expense was based on the September 29, 2006 unit closing price of $6.93, distributions of $0.15 per unit from January to April and $0.12 distributions per unit from May to September as well as management's estimate of the number of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs") to be issued on maturity. No estimate has been made for forfeitures. The following table summarizes the RTU and PTU movement for the three and nine months ended September 30, 2006.

Restricted and Performance Trust units *(000s)*	**RTUs**	**PTUs**
Balance December 31, 2004	-	-
Granted	283	59
Balance December 31, 2005	283	59
Granted	6	1
Cancelled	(3)	(1)
Balance March 31, 2006	286	59
Granted	224	104
Cancelled	(3)	-
Redeemed	(104)	-
Balance June 30, 2006	403	163
Granted	5	1
Cancelled	(30)	(11)
Balance September 30, 2006	**378**	**153**

Unit-based compensation *($000s)*	
Balance December 31, 2004	$ -
Unit-based compensation	1,295
Balance December 31, 2005	$ 1,295
Unit-based compensation	548
Balance March 31, 2006	$ 1,843
Unit-based compensation	204
Vested Restricted Trust Units	(1,301)
Balance June 30, 2006	$ 746
Unit-based compensation	549
Balance September 30, 2006	**$ 1,295**

(d) Per Unit Amounts

The following table summarizes the weighted average Trust units, exchangeable shares and convertible debentures used in calculating net income per Trust unit:

	Three Months Ended September 30		Nine Months Ended September 30	
Trust units *(000s)*	**2006**	2005	**2006**	2005
Weighted average Trust units	**48,154**	40,755	**46,541**	39,567
Exchangeable shares at exchange ratio	**489**	3,328	**854**	3,466
Trust units (basic)	**48,643**	44,083	**47,395**	43,033
Convertible debentures	**6,731**	-	**6,731**	-
Restricted and Performance Trust Units	**473**	309	**343**	1,486
Trust units (diluted)	**55,847**	44,392	**54,469**	44,519

Diluted Trust units include the dilutive impact of units issuable under the Trust Unit Incentive Plan. Diluted net income per unit adds back the effect of the convertible debentures which included an adjustment to net income of $1.0 million and $2.0 million, respectively for the three and nine months ended September 30, 2006.

9. Financial Instruments

The Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contracts	Volume GJ/d	Pricing Point	Strike Price per GJ	Term
Costless Collar	15,000	AECO	Cdn$6.00 to Cdn$6.50	April 1/06 to Oct 31/06
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$9.40	Nov 1/06 to March 31/07
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$10.00	Nov 1/06 to March 31/07

Oil Contracts	Volume bbls/d	Pricing Point	Strike Price per bbl	Term
Costless Collar	800	WTI NYMEX	US$61.00 to US$72.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$73.05	Jan 1/07 to Mar 31/07
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to Mar 31/07

The net effect of these contracts was a realized loss of $0.7 million and an unrealized gain of $8.2 million during the three months ended September 30, 2006 and a realized loss of $1.9 million and unrealized gain of $6.0 million during the nine months ended September 30, 2006.

Subsequent to September 30, 2006, the Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contract	Volume GJ/d	Pricing Point	Strike Price per GJ	Term
Costless Collar	10,000	AECO	Cdn$6.50 to Cdn$8.10	April 1/07 to Oct 31/07

Oil Contracts	Volume bbls/d	Pricing Point	Strike Price per bbl	Term
Costless Collar	800	WTI NYMEX	US$60.00 to US$70.50	April 1/07 to June 30/07
Costless Collar	800	WTI NYMEX	US$60.00 to US$72.50	July 1/07 to Sept 30/07

10. Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. To the extent that cash distributions represent taxable distributions to the unitholders, the distributions will reduce the Trust's future income tax expense. Income taxes recorded in the consolidated statements of income and retained earnings differ from the tax calculated by applying the combined Canadian corporate federal and provincial income tax rate to income before taxes as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
Income taxes *($000s)*	**2006**	2005	**2006**	2005
Statutory income tax rate for the period	**35.03%**	37.75%	**35.03%**	37.75%
Computed income tax expense (recovery)	**$ 966**	$ 2,511	**$ (1,733)**	$ 7,017
Add (deduct) income tax effect of:				
Non-deductible Crown charges, net of ARTC	**(43)**	1,798	**(131)**	2,939
Resource allowance	**-**	(1,784)	**-**	(3,421)
Estimated taxable distribution	**(5,411)**	(6,342)	**(17,408)**	(6,342)
Tax rate adjustments	**(675)**	(53)	**(17,060)**	(979)
Unit-based compensation	**193**	2,307	**456**	2,983
Other	**21**	121	**42**	20
Future income tax	**(4,949)**	(1,442)	**(35,834)**	2,217
Income tax	**(552)**	375	**158**	788
Provision for income taxes (recovery)	**$ (5,501)**	$ (1,067)	**$ (35,676)**	$ 3,005

11. Supplemental Cash Flow Information

Supplemental cash flow information *($000s)*	Three Months Ended September 30 **2006**	2005	Nine Months Ended September 30 **2006**	2005
Changes in non-cash working capital:				
Accounts receivable	**$ 4,699**	$ (22,441)	**$ 9,364**	$ (12,902)
Prepaid expenses	**(949)**	(2,561)	**(922)**	(2,180)
Accounts payable and accrued liabilities	**(9,872)**	20,474	**(17,112)**	(7,127)
	$ (6,122)	$ (4,528)	**$ (8,670)**	$ (22,209)
Changes in non-cash working capital:				
Operating activities	**10,518**	7,254	**$ 992**	$ (19,488)
Investing activities	**(16,640)**	(11,782)	**(9,662)**	(2,721)
	$ (6,122)	$ (4,528)	**$ (8,670)**	$ (22,209)
Cash payments made for interest	**$ 1,042**	$ 1,411	**$ 3,949**	$ 3,507
Cash payments made for taxes	**$ 101**	$ 5	**$ 1,686**	$ 66

12. Related Party Transactions

During the three and nine months ended September 30, 2006, the Trust incurred expenditures of $0.2 million and $0.5 million, respectively for general corporate legal fees to a legal firm of which a director is a partner. These legal fees were included in general and administrative expenses, convertible debenture issue costs, property and equipment and unit issue costs. At September 30, 2006, $14,000 was included in accounts payable. The related party transactions were recorded at the exchange amount as services were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.