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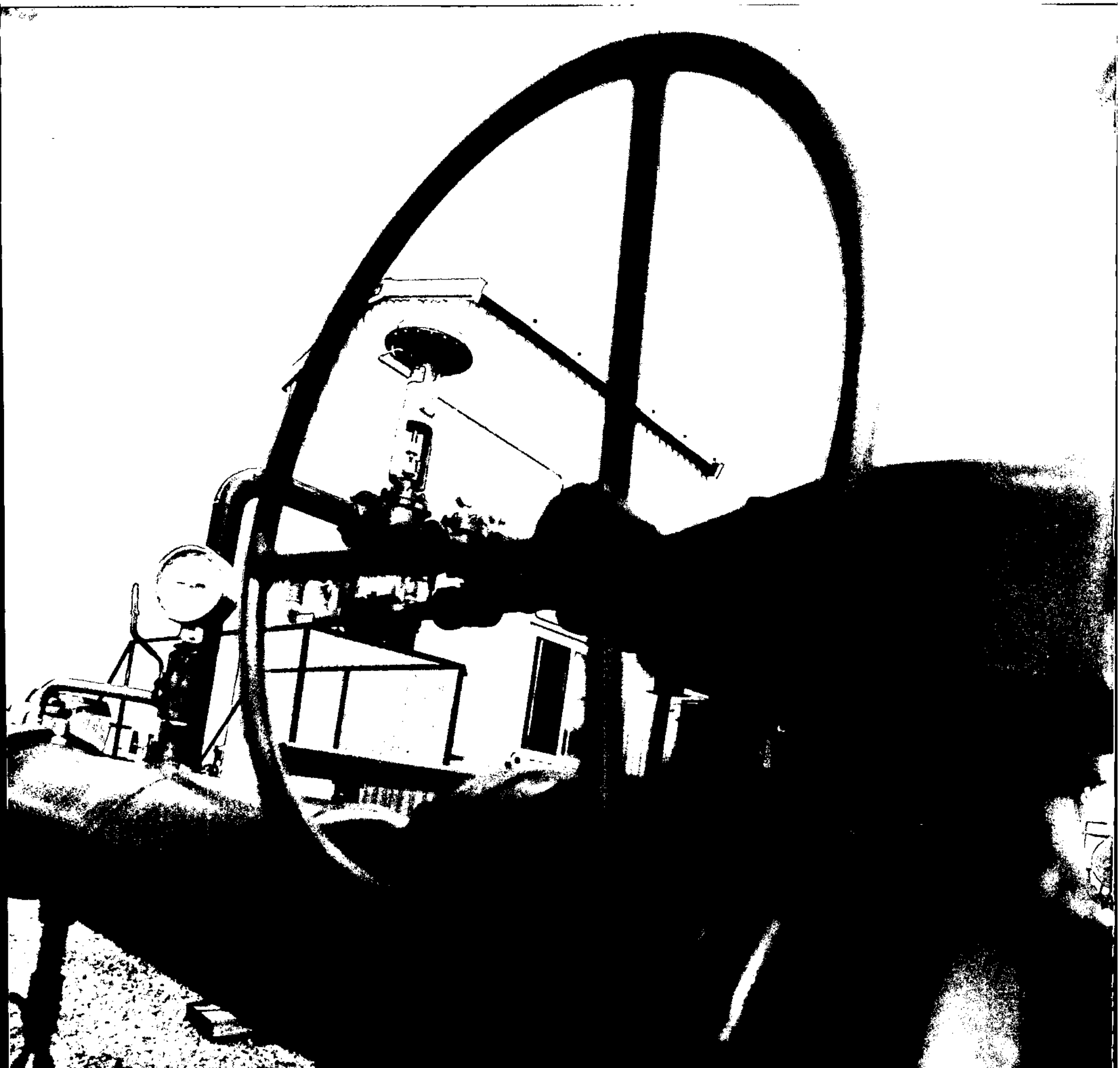


THUNDER ENERGY TRUST

MESSAGE FROM THE PRESIDENT

We remain committed to the strategic elements of our business, despite the operational issues that have challenged us this past year. That is why Thunder is embarking on a thorough strategic review of the structure of the Trust and our options for the future. In early March, management along with the Board of Directors, determined it was in the best interests of the Trust and, indeed, all of our stakeholders to examine strategic alternatives. The process is underway with Thunder and our financial advisors examining a range of options including, but not limited to, a merger, internal restructuring, the acquisition or disposition of select assets, or the continuation of our current strategic plan.

What remains of utmost importance is continuing to manage our assets in a fashion that will preserve and create value. Upon releasing our 2006 results, there were many factors challenging Thunder and it is important that our stakeholders understand what these were, and how we are managing a go-forward operational plan.

Our 2006 results were impacted by market conditions, short-term operational issues and the release of our independently prepared year-end reserves report. At year-end 2006, revisions to our reserves led to a $102.0 million write-down in our plant and property assets, and an additional write-down of $58.6 million in goodwill related to the formation of the Trust in July 2005.

At the same time that we released our year-end results, we announced a reduced guidance for the Trust of 8,600 to 9,000 boe/d for 2007, which was issued after an evaluation of a number of our properties, drilling activity and our reserves. We expect our first half production volumes to be soft, reflecting the temporary shut-in of approximately 350 boe/d due to operational issues such as delays in facility construction and turnarounds at third party plants.

One of the motivating factors behind the evaluation of strategic alternatives is that we are fully aware that, relative to most of our peers, Thunder has been undervalued in equity markets. The main reason, we believe, was that the investment community needed to see reliable and stable production volumes over an extended period of time. In 2006, beginning with the second quarter, we demonstrated stable production with 9,307 boe/d in Q2; 9,229 in Q3 through to 9,279 boe/d in Q4. Over those quarters, we were able to arrest our base production declines to approximately 24% per annum, and flatten production, averaging 9,272 boe/d. Our revised guidance for 2007 principally reflects temporary production shut-ins and a delay in facility construction in certain areas.

BUILDING OUR KNOWLEDGE BASE

It should be remembered that the Trust was formed in mid-2005 with the merger of assets from three entities. Much was achieved in 2006 by our technical staff in understanding the engineering and geological intricacies of those properties. With acquisition prices still high, our focus was the drill bit, and to develop a more thorough understanding of the risks and rewards across our undeveloped asset base. The learning curve was steep, as many of our professionals were new to the variety of assets. Today, each property in our portfolio has undergone a thorough assessment of risk. To further our knowledge base, in the first half of 2006, we completed our initial assessment of 3D seismic purchased in 2005, which in 2006 yielded 3D targeted drilling success of approximately 80%. Furthermore, a large 3D data set received in Q4 2006 is currently under review. Coupled with our 2007 seismic capital, Thunder will have an extensive 3D seismic database covering approximately two-thirds of our current conventional drilling inventory. It is my understanding that no other trust of similar size in the energy market can match such an extensive library of data.

While interpretation of the 3D seismic is ongoing, our geotechnical teams have generated an exceptional and varied opportunity base of firm development and exploration inventory on our existing assets. These include:

- Greater than four years of defined drilling inventory, with more than 65% of conventional plays backed by 3D seismic.
- Over 24 townships (more than 880 square miles) of 3D seismic, which has yielded significant drilling success and additional location inventory. Thunder's 2D and 3D seismic has an independently assessed fair market value of approximately $23 million.
- Undeveloped land holdings totalled approximately 165,284 net acres at December 31, 2006 with a current market value of roughly $31 million.
- Proved producing reserve additions of 5.1 million boe, despite downward technical revisions in the proved plus probable category of 4.5 million boe.

With those internally-generated opportunities in place, Thunder possesses an asset base with attractive attributes and a variety of growth-oriented projects.

HIGHER-REWARD DRILLING

Our drilling inventory speaks to our technical abilities not only to identify opportunities, but also our ability to 'science down the risk' across our assets. We have developed techniques and methodologies, which allow us to set up realistic expectations in our drilling programs. A statistical approach to the development of our assets ensures our models are properly risk-adjusted. This enhances Thunder's ability to forecast economic returns with greater accuracy – and to deliver on those forecasts. This continuous real-time analysis of all project economics is imperative considering the high volatility in commodity markets. In addition, having such a technical edge on our assets has allowed us to high grade our drilling inventory.

In some areas, we are pursuing what are normally considered higher-risk plays. One aspect of our risk management strategy is our unique strategic partnerships through which we are pursuing higher-risk, higher-reward targets, while adjusting down our risk exposure. For example, we are pursuing higher-reward plays at Sylvan Lake which are targeting Leduc reef complexes. Seismic modelling at Leduc has led to a much higher level of understanding as demonstrated by our drilling results. Corporately in 2006, of the 16 drills based on 3D seismic, we were successful 13 times. That is only one example of how our ability to 'science down the risk' is being achieved by bringing together the skills of our people with leading geotechnical knowledge and tools.

YEAR-END RESERVES WRITE-DOWN

Just as we have moved to an in-depth understanding of our opportunities, we are also gaining greater knowledge of our reserve base. When combined with an overall weakness in gas prices, at year-end 2006, the independent reserve report yielded a write-down of approximately 14% based on proved plus probable reserves to 29.4 mmboe. Approximately 82% of proved plus probable downward reserve revisions were from four properties: Whiskey Creek (39%), Rosalind (18%), Sylvan Lake (14%) and Fenn-Big Valley (11%). Proved producing reserves are now approximately 85% of total company-interest proved reserves, a significant improvement from last year's level of approximately 66%.

Today we are more confident of the assets in our portfolio and of their potential both in the near and longer term.

IMPACT OF GAS PRICES

Ours is a cyclical business and, in terms of gas prices, we believe we reside in a short-term trough. In January 2006 gas prices began a hard slide from the $12 per mcf range to less than $5 per mcf in September. Across our sector, reduced cash flow levels resulted in distribution reductions. While an active hedging program supports our cash flow, the significant drop in gas prices led to a reduction in our monthly distributions to $0.12 per unit from $0.15 per unit that had been in place since inception of the Trust. Continued soft prices led to a further reduction to $0.09 per unit in the first quarter of 2007. Gas prices have firmed somewhat since the beginning of the year; however, we believe market volatility will continue to be a certainty throughout the year.

THE GOVERNMENT'S PROPOSAL TO TAX TRUSTS

On October 31 the federal government announced its intention to change the tax regime for royalty trusts. The proposed tax changes have not yet been enacted. Recommendations from the multi-party House of Commons Finance Committee have been released and we hope government will see the importance of changing their stance. The government's current time-line for the tax changes is a four-year transition period with the new regime to take effect January 1, 2011; the Finance Committee is recommending an extension to ten years, and specific considerations being given to certain industry sectors, notably the energy industry.

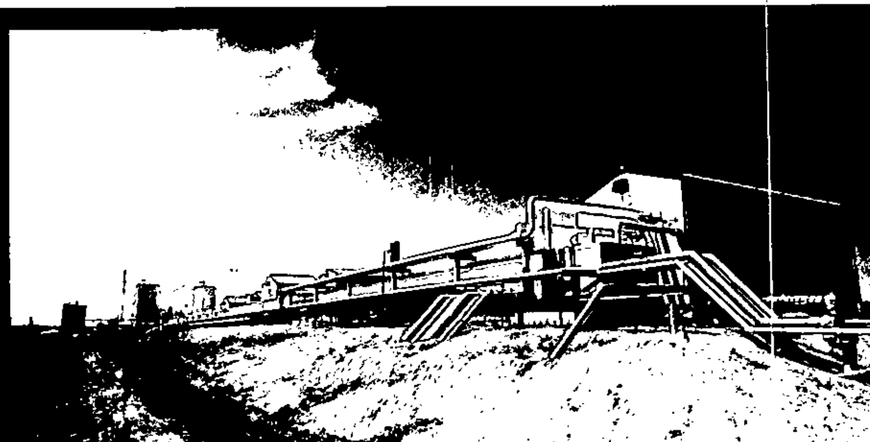
Under any tax regime that might be enacted, Thunder is advantaged against the majority of trusts by the level of tax pool coverage. At December 31, 2006, Thunder's tax pools were an estimated $337 million, which provides Thunder with more than a four-year tax horizon, given current levels of production and capital expenditure activity. Many aspects of our industry will be forced to adjust to the new environment, some of which are impossible to predict at this point; however, we see a number of elements coming into play.

80% success in 3D targeted drilling

Proved producing reserves at 85% of total company-interest proved reserves

Extensive 3D seismic database covering two-thirds of drilling inventory

Forecasted more than four years of defined drilling inventory



We believe that there will continue to be investor demand for a yield-based product, whether pre- or post-tax, which will support a trust-based industry in the oil and gas sector. We expect rationalization to occur leaving the sector with fewer, but larger trust entities, and those that remain will be challenged to continue to maintain or grow their production base. Likely, we will see these larger players moving to higher reward operations in the international theatre. To remain competitive, these trusts will require a critical mass in their level of capitalization to continue to reward unitholders. It is difficult to predict what the sector will look like, but it is possible to see opportunities for technically savvy operators.

IMPROVING ACQUISITION MARKETS

During 2006, Thunder's acquisition activity was limited as opportunities available failed to meet our strict financial and operating hurdle rates. In 2007, a more realistic value of discounted future cash flows is beginning to evolve in response to the weakness in commodity prices and the government's proposed tax changes. It is becoming apparent that sellers' expectations are changing, which should result in acquisition prices being adjusted down. We expect to see significant downward pressure on acquisition prices in 2007, which should present excellent opportunities for the trust sector.

GUIDANCE FOR 2007

In 2007, we expect to sustain production at 8,600-9,000 boe/d through associated capital expenditures of $62 million, 55% weighted to oil projects. An active drilling program will target 57 wells (30.8 net). Our capital program will be funded by cash flow, our Distribution Reinvestment Plan (DRIP), and a small draw on our credit facility.

IN CLOSING

Strategic management of our assets has been a critical focus at Thunder. Since our formation in mid-2005, which was accomplished by bringing together a variety of properties from three oil and gas entities, we have always had an eye on creating an energy trust that delivers on many fronts – a great place to work, an economic contributor to our business communities and, most importantly, the ability to create value for our unitholders.

I would like to personally thank our employees for their dedication and efforts, and our Board of Directors for their leadership and insight. As a team, we remain committed to doing what is right for Thunder and our unitholders in the short and long term. The challenges ahead are many, but our efforts will remain focused on a sound operational plan, and the thorough investigation of all strategic alternatives in order to ensure Thunder is maximizing value to all of its stakeholders.

On behalf of the Board

Stuart J. Keck
President and Chief Executive Officer

March 28, 2007

Sustain production at 8,600 – 9,000 boe/d

Continue an active drilling program targeting 57 wells (30.8 net)

Retain strict acquisition framework

OPERATIONS REVIEW

Thunder continues to generate drilling and exploitation opportunities to maintain production. The 2D seismic database is now 2,465 miles. The 3D seismic database has grown to 880 square miles. Thunder has a drilling inventory for over 4 years and it continues to expand. In 2006 Thunder's drilling success rate was 81% and drilling is now enhanced with 3D seismic in most areas.

- 87% of production operated
- 62% gas, 38% oil & NGL
- Oil averages 35° API
- 679,790 acres (379,776 net) of total developed and undeveloped land
- 165,284 net acres of undeveloped land
- Thunder owns gas processing capacity of 45 mmcf/d. The Trust has high working interests in most facilities and operates gas processing plants in the Central Alberta core areas of Rosalind, Fenn-Big Valley, Matziwin and Clive.
- Thunder has oil processing capacity exceeding 7,500 bbls/d. Thunder operates about 75% of its oil facilities at high working interests.
- Thunder operates about 1,200 km (750 miles) of oil and gas gathering pipelines.

- Total well drilling inventory currently 431 gross (315 net).
- 2007 budget of 57 (30.8 net) wells for drilling.
- Average working interest in 2007 drilling program ~ 55%.
- A significant number of producing wells have additional zones with recompletion potential.

- 88% average working interest in production
- 95% of production is operated
- 73.5% average working interest in 339,222 acres; 92,137 net undeveloped acres

- 18% average working interest in production
- 41% of production is operated
- 30% average working interest in 198,979 acres; 31,640 net undeveloped acres

- 58% average working interest in production
- 100% of production is operated
- 70% average working interest in 4,477 acres; 1,279 net undeveloped acres

- 39% average working interest in production
- 85% of production is operated
- 38% average working interest in 46,760 acres; 9,156 net undeveloped acres

- 68% average working interest in production
- 100% of production is operated
- 46% average working interest in 32,513 acres; 7,570 net undeveloped acres

- 81% average working interest in production
- 95% of production is operated
- 60% average working interest in 13,040 acres; 7,889 net undeveloped acres

PROPERTY OVERVIEW

Central Alberta

Central Alberta is Thunder's largest producing region accounting for 56% of total daily volumes. On a boe basis, 81% of production is natural gas, 19% is oil and NGL. The primary natural gas producing areas are Rosalind, Manola, Fenn-Big Valley, Clive and Matziwin. Clive is a coalbed methane property producing mostly from the Horseshoe Canyon coals with some production from the Belly River fluvial sands. The main oil producing areas in Central Alberta are Rosalind and Redwater. Exploitation activities have been predominantly in Rosalind, Manola and Redwater.

The primary drilling targets are low-risk with multi-zone potential. In 2007 Thunder is planning to drill 26 (21 net) wells in Central Alberta. A number of extensive 3D seismic programs are planned for 2007.

Major Projects

Fenn-Big Valley – Thunder has drilled wells on a campaign basis with Ember Resources Inc. and plans are in place to continue this development procedure. Thunder completes the Belly River zones and Ember completes their Horseshoe Canyon CBM intervals. This arrangement has significantly reduced Thunder's development costs and future operating costs. Thunder added 4.5mmcfd of gas processing capacity in 2006 by participating in an expansion of a non-operated gas processing facility.

Manola – A large 3D seismic program was undertaken in early 2006, which defined a significant number of multi-zone drilling opportunities. Two successful Wabamun wells were drilled on the 3D and one successful Rex (Lower Mannville) well on existing 2D. In the first quarter of 2007, Thunder completed a 16.2 square mile shoot of 3D seismic.

Rosalind – Four Belly River tests (50% WI) and four Lower Mannville tests (100% WI) were drilled in 2006 resulting in four Belly River gas wells, three dual zone Lower Mannville gas wells and one D&A. Over 30 net drilling locations have now been identified and an additional 6.91 square miles of 3D seismic has been shot in Q1 2007.

Matziwin – In 2006 one well was drilled (100% WI) targeting a Glauconite channel offsetting two Thunder gas producers. This well not only encountered the target Glauconite channel but also made an Ellerslie oil discovery. In 2007 eight locations are planned using existing 3D seismic and a 14.61 square mile 3D seismic program has been shot in the first quarter of 2007, targeting additional Mannville opportunities.

Southern Alberta

Skiff – In the Skiff area a number of drilling, recompletion, reactivation activities and a water flood study have commenced to prepare for a full water flood of the Sawtooth formation. The preliminary results of the water flood study indicate that the Sawtooth oil pool is an outstanding candidate for water flood and for enhanced oil recovery. In 2007 additional drilling, construction and laboratory work is planned.

Western Alberta

Western Alberta is made up of four properties: Sylvan Lake, Ferrybank, Medicine River and Ferrier. The District accounts for 16% of Thunder's production, 69% light, sweet oil and 31% gas. Thunder operates the majority of producing properties and has an 80% working interest in a 2,500 bbls/d oil-treating facility. Thunder is participating in a facility expansion that will add 1,250 bbls of net oil processing capacity.

Development of high impact Leduc reefs is being pursued in Sylvan Lake through a strategic alliance with Alberta Clipper Energy Inc. Thunder has extensive 3D seismic coverage over the properties, which is essential for identifying step-out drilling locations and evolving play types. Nine (3.6 net) wells are planned for drilling in 2007. In Ferrybank, Medicine River and Ferrier, Thunder and partners are drilling for multi-zone targets.

Northern Alberta

The Northern Alberta region accounts for 15% of Thunder's production from three areas: Red Earth, Peace River Arch and Pembina. Production is 61% oil and 39% gas. Thunder operates five oil-treating facilities, with an average working interest of 86% and processing capacity of 2,300 bbls/d. Thunder also holds about 500 bbls/d of non-operated working interest processing capacity in several other facilities.

Thunder has an extensive database of 3D seismic (146 square miles) in this area and is developing a number of drilling prospects.

Northeast B.C.

Thunder has working interests in two Northeast B.C. properties, Buick Creek and Laprise. The region accounts for less than 5% of Thunder's production, but has significant growth potential.

At Laprise, Thunder is evaluating plays in the Baldonnel and the Bluesky formations. Both zones hold large potential gas resources. While the Bluesky can be accessed by vertical wells, the Baldonnel requires horizontal wells for effective development. Thunder has extensive 3D seismic coverage over the Laprise lands.

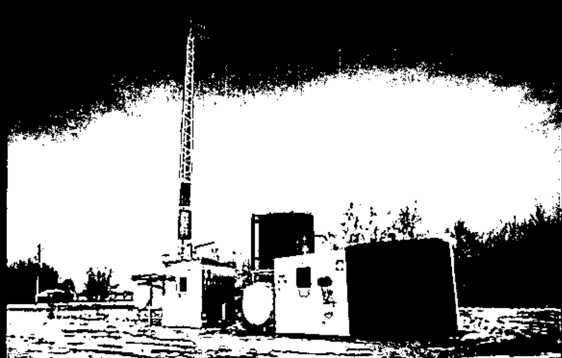
Foothills

Thunder's Whiskey Creek operations are producing from reserves in the Mississippian formation. The area has large potential resources based on internal seismic interpretation.

Thunder is currently producing gas from three operated wells at the Whiskey Creek field and will optimize field performance by installing compression in early 2008.

Saskatchewan

Thunder's Saskatchewan properties are located in the southeast portion of the province at Mansur, Workman and Willmar. The area produces oil and accounts for less than 5% of Thunder's production. Thunder operates four batteries and more than 80% of the production.



Thunder has a drilling inventory for over 4 years and it continues to expand.

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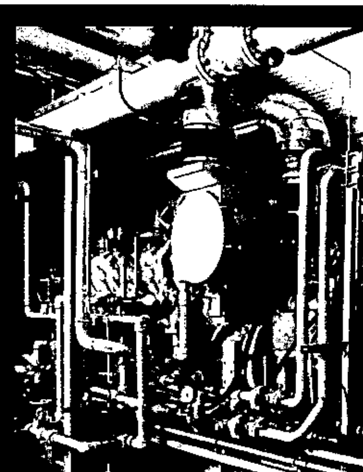

HEALTH, SAFETY AND ENVIRONMENT

Thunder conducts its operations with the utmost regard for the environment and the health and safety of its employees, contractors and the public. We recognize that safe practices, healthy working conditions and conservation of our environment are essential to achieve sustainable profitability and continuity for our company, unitholders and employees.

The Trust operates its Health, Safety and Environment program under the auspices of the Alberta Human Resources and Employment Certificate of Recognition (COR). This program follows the guidance of:

- Occupational Health and Safety
- Workers Compensation Board program guidelines
- Petroleum Safety Council

As part of an ongoing commitment to environmental stewardship, Thunder is actively involved in industry programs.

- Thunder is committed to CAPP's Stewardship principles of, "Continuous improvement and transparent reporting of environmental, health, safety and social performance".
- Thunder is registered with the National Pollutant Release Inventory (NPRI). "The NPRI is a major starting point for identifying and monitoring sources of pollution in Canada. It is an important consideration in managing risks to the environment and human health as well as in monitoring indicators for the quality of our air, land, and water. It is also emerging as an indicator for corporate environmental performance."

RESERVES SUMMARY

GLJ Petroleum Consultants ("GLJ") evaluated the oil and natural gas reserves as at December 31, 2006 in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Company interest reserves as at December 31, 2006, as evaluated by GLJ based on forecast prices and costs, were 20.4 mmboe proved and 29.4 mmboe proved plus probable.

Year-end reserves include upward technical revisions, which includes conversion of non-producing reserves to producing of 2.1 mmboe proved producing and downward technical revisions of 2.4 mmboe total proved. Overall there were downward revisions of 4.5 mmboe proved plus probable. Three mmboe of proved plus probable reserves were added from drilling, enhanced recovery and including minor acquisitions and divestitures.

Based on GLJ's 2007 production estimate, the reserve life index stands at 8.1 years (proved plus probable) and 6.0 years (proved).

In the GLJ reserves report downward proved plus probable reserve revisions were principally from four properties: Whiskey Creek, Rosalind, Sylvan Lake and Fenn-Big Valley. These four properties accounted for approximately 82% of the downward revisions. The negative revisions resulted mainly from production performance of mature wells, from water production truncating the economic life of some wells and, to a lesser extent, delays in construction of production facilities.

At year end 2006, Thunder had increased the ratio of proven reserves to 85% proven producing reserves up from 66% at year end 2005.

The 2006 reserves additions from drilling and development occurred in a number of areas. The biggest area contributors to additional proven and probable reserves were Rosalind, Sylvan Lake region, Manola and Fenn-Big Valley. These four areas contributed to approximately 74% of the proven plus probable reserve additions.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Company Interest Reserves					Net Reserves after Royalties				
	Light and Medium Crude Oil (mbbls)	Heavy Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Oil Equivalent (mbbls)	Light and Medium Crude Oil (mbbls)	Heavy Crude Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Oil Equivalent (mbbls)
Proved										
Developed producing	4,504	248	1,072	69,134	17,347	3,999	238	748	55,383	14,215
Developed non-producing	223	0	73	8,938	1,786	187	0	48	7,156	1,428
Undeveloped	318	145	72	4,340	1,259	248	138	49	3,284	983
Total proved	5,046	394	1,216	82,411	20,391	4,434	376	845	65,823	16,626
Probable	1,656	238	655	38,683	8,995	1,440	226	475	30,447	7,215
Total proved plus probable	**6,701**	**632**	**1,871**	**121,093**	**29,387**	**5,874**	**602**	**1,320**	**96,270**	**23,842**

Amounts may not add exactly due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at				
($000s)	0%	5%	10%	15%	20%
Proved					
Developed producing	468,986	358,827	299,169	260,130	232,008
Developed non-producing	50,290	34,284	26,030	21,071	17,757
Undeveloped	23,806	17,613	13,262	10,096	7,727
Total proved	543,082	410,724	338,461	291,298	257,492
Probable	240,317	143,314	97,880	72,276	56,156
Total proved plus probable	**783,399**	**554,038**	**436,342**	**363,574**	**313,648**

Amounts may not add exactly due to rounding.

Pricing Assumptions – Forecast Prices and Costs

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2006 in estimating the above reserves data using forecast prices and costs. The weighted average historical prices received by the Trust for 2006 are also reflected in the table below.

	Natural Gas		Crude Oil		Natural Gas Liquids		
Year	Henry Hub (US$/mmbtu)	Spot Plant Gate (Cdn$/mmbtu)	WTI Cushing Oklahoma 40° API (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Pentanes Plus Edmonton (Cdn$/bbl)	Butanes Edmonton (Cdn$/bbl)	Exchange Rate ($US/$Cdn)
2006 (Actual)	7.26	6.96	66.22	73.16	75.69	66.64	0.882
2007	7.25	7.00	62.00	70.25	71.75	56.25	0.870
2008	7.50	7.25	60.00	68.00	69.25	50.25	0.870
2009	7.50	7.55	58.00	65.75	67.00	48.75	0.870
2010	7.50	7.60	57.00	64.50	65.75	47.75	0.870
2011	7.50	7.65	57.00	64.50	65.75	47.75	0.870
2012	7.75	7.95	57.50	65.00	66.25	48.00	0.870
2013	7.90	8.10	58.50	66.25	67.50	49.00	0.870
2014	8.05	8.30	59.75	67.75	69.00	50.25	0.870
2015	8.20	8.50	61.00	69.00	70.50	51.00	0.870
2016	8.40	8.65	62.25	70.50	72.00	52.25	0.870
2017	8.55	8.85	63.50	71.75	73.25	53.00	0.870
Thereafter	Escalate at 2 percent per year						0.870

PRODUCTION VOLUME BY FIELD

The following table indicates the average daily production from the Trust's properties for the year ended December 31, 2006.

Field	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (boe/d)
Rosalind	292	–	6,079	20	1,325
Manola	145	–	4,884	21	980
Matziwin	176	–	3,971	16	854
Fenn-Big Valley	85	–	6,595	–	1,184
Laprise	36	–	2,120	57	446
Whiskey Creek	–	–	840	34	174
Sylvan Lake/Medicine River	900	–	2,695	162	1,511
Clive	4	–	3,724	2	627
Redwater	225	–	219	–	262
Greater Red Earth	661	–	474	2	742
Saskatchewan	369	–	–	–	369
Other	168	139	3,480	91	978
Total	**3,061**	**139**	**35,081**	**405**	**9,452**

HEDGING STRATEGY

As with all trusts, the Trust has limited control over fluctuations in the price of oil and gas. To mitigate the effects of changes in commodity prices, the Trust implemented a hedging strategy in early 2006. This strategy will not be used to speculate on future prices, but it will be used to help stabilize cash flow, thereby protecting the near term capital expenditure budget and cash distributions to Unitholders. We currently have the following hedges in place:

Natural Gas Contracts	Volume (gj/d)	Pricing Point	Strike Price (per gj)	Term
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
Costless collar	10,000	AECO	Cdn$6.50 to Cdn$8.10	April 1/07 to Oct 31/07
Costless collar	8,000	AECO	Cdn$6.50 to Cdn$8.00	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$61.00 to US$73.05	Jan 1/07 to March 31/07
Costless collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to March 31/07
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

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 2006 and prior years, as well as estimates of future operating and financial performance based on information currently available. It should be read in conjunction with the audited consolidated financial statements of the Trust for the years ended December 31, 2006, and 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 March 2, 2007.

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

The following are descriptions of non-GAAP measures used in this MD&A:

This MD&A contains the term funds from operations to evaluate operating performance and leverage. Funds from operations and funds from operations per unit as presented and as used in the MD&A do not have any standardized prescribed meaning under GAAP and therefore may not be comparable with the calculation of similar measures of other entities. Funds from operations does not represent operating profit for the year nor should it be viewed as an alternative to operating profit, net income (loss) or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations throughout the MD&A are based on cash provided by operating activities before changes in non-cash working capital relating to operating activities and the settlement of asset retirement obligations.

Payout ratio as used in the MD&A does not have any standardized meaning under GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. The payout ratio is calculated using distributions declared divided by funds from operations. Payout ratio is a useful measure used by management to analyze the Trust's efficiency and sustainability.

Distributable cash from operations is not a measure under GAAP and there is no standard measure of distributable cash from operations. Distributable cash from operations is calculated as funds from operations less capital expenditures funded by operations.

Operating netbacks per boe equal total petroleum and natural gas revenue net of transportation expenses and realized gains on commodity contracts per boe less royalties per boe and operating expenses per boe. Cash flow netbacks from operations equal operating netbacks less all other cash expenses per boe. Operating netbacks and cash flow netbacks as used in the MD&A does not have any standardized meaning under GAAP and therefore may not be comparable with the calculation of similar measures of other entities. Operating netbacks and cash flow netbacks are a useful measure to compare the Trust's operations with those of its peers.

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 to 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.

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

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 production 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 this MD&A under the headings "Critical Accounting Estimates" and "Risks and Uncertainties".

The Trust cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on the Trust's 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

FINANCIAL RESULTS

($000s, except per unit amounts)	**2006**	2005
Petroleum and natural gas sales	**169,977**	195,778
Funds from operations[1]	**79,014**	110,391
Per unit – basic	**1.65**	2.47
Per unit – diluted	**1.51**	2.46
Net income (loss)	**(99,466)**	(9,851)
Per unit – basic	**(2.07)**	(0.22)
Per unit – diluted	**(2.07)**	(0.22)
Capital expenditures	**86,944**	88,394
Net debt including working capital deficiency	**204,225**	154,643
Total assets	**654,370**	817,390

[1] Funds from operations is calculated as cash from operating activities before the settlement of asset retirement obligations and changes in non-cash working capital relating to operating activities.

RESULTS OF OPERATIONS

Petroleum and Natural Gas Revenues

Oil and gas revenues decreased 13% to $170.0 million for the year ended December 31, 2006 compared with 2005. The 35% decline in natural gas sales to $85.4 million is due to a 26% decline in the price of natural gas at the wellhead and a 13% decline in natural gas production compared to the prior year. Crude oil and NGL sales increased 32% to $84.6 million due to a 33% increase in crude oil and NGL production. The average crude oil and NGL price remained flat with 2005. Production is targeted at 8,600 to 9,000 boe per day in 2007, 62% to be natural gas.

The table below calculates revenues and segregates transportation costs.

PETROLEUM AND NATURAL GAS REVENUES ($000s)	2006	2005
Natural gas sales	**85,371**	131,742
Crude oil and NGL sales	**84,606**	64,036
Gross revenues	**169,977**	195,778
Transportation expenses	**(5,615)**	(6,383)
Net revenues	**164,362**	189,395
Realized net gain on commodity contracts	**724**	–
Net revenues after realized gain on commodity contracts	**165,086**	189,395
Unrealized net gain on commodity contracts	**4,558**	–
Net revenues after realized and unrealized gains on commodity contracts	**169,644**	189,395

SALES VARIANCE ANALYSIS ($000s, net of transportation expenses and realized commodity contract gain/loss)	2006	2005
Natural gas sales		
Effect of change in sales volumes	**(16,651)**	3,210
Effect of change in product prices	**(28,551)**	31,767
Effect of realized gain on commodity contracts	**2,600**	–
Net natural gas sales change	**(42,602)**	34,977
Crude oil and NGL sales		
Effect of change in sales volumes	**20,521**	20,789
Effect of change in product prices	**(352)**	21,445
Effect of realized loss on commodity contracts	**(1,876)**	–
Net crude oil and NGL sales change	**18,293**	42,234
Combined sales change	**(24,309)**	77,211

PRODUCTION	2006	2005
Natural gas (mcf/d)	**35,081**	40,349
Crude oil and NGL (bbls/d)	**3,605**	2,706
Total (boe/d)	**9,452**	9,431
Percentage gas (%)	**62**	71

Marketing

The Trust markets its natural gas in the Alberta spot market and through aggregators, which sell to major markets in Canada and the United States. Aggregator prices are based on a combination of term and spot markets. Crude oil and NGL are sold on a spot basis at various delivery points in Alberta. Prices received for crude oil and NGL are determined by the quality of the crude compared to a benchmark price for light sweet oil. The Trust's current composite crude oil is a medium blend averaging approximately 35° API (2005 – 33° API); whereas, the Edmonton light price is 40° API.

The Trust continually monitors commodity markets to determine the appropriate marketing of its products including hedging production. In 2006, approximately 83% (2005 – 83%) of natural gas sales were to the higher value Alberta spot market and the remaining 17% was hedged at a monthly average price. The Trust received an average natural gas price at the wellhead of $6.43 per mcf, $0.11 per mcf lower than AECO, but before a $0.20 per mcf commodity contract gain. The Trust's average price for crude and NGL was discounted to the Edmonton light posted price by $10.48 per bbl before a commodity contract loss of $1.43 per bbl (2005 – $6.16 per bbl).

Commodity prices received by the Trust are based on the respective reference prices for both crude oil and natural gas adjusted for transportation and quality differentials, as applicable, and foreign exchange. For the year, the Trust's average crude oil and NGL price at the wellhead remained steady with the 2005 average price; whereas, the average natural gas price decreased 26%.

AVERAGE COMMODITY PRICES	2006	2005
Natural gas ($/mcf)		
NYMEX ($US/mmbtu)	**7.27**	8.58
AECO Daily ($/mmbtu)	**6.54**	8.77
Thunder price before commodity contracts and transportation	**6.66**	8.94
Transportation	**(0.23)**	(0.28)
Thunder price at the wellhead	**6.43**	8.66
Realized gain on commodity contracts	**0.20**	–
Thunder price after commodity contracts	**6.63**	8.66
Crude oil ($/bbl)		
WTI ($US/bbl)	**66.22**	56.56
Edmonton posted	**72.77**	68.72
Thunder price before commodity contracts and transportation	**64.29**	64.82
Transportation	**(2.00)**	(2.26)
Thunder price at the wellhead	**62.29**	62.56
Realized loss on commodity contracts	**(1.43)**	–
Thunder price after commodity contracts	**60.86**	62.56
Cdn/US $ average exchange rate	**1.134**	1.208

Transportation expenses relate to the cost of transporting natural gas on the main natural gas pipelines and for crude oil trucking charges. In 2006, transportation expenses decreased 12% to $5.6 million due to the decline in natural gas production. Natural gas transportation increased in the second half of 2005 to $0.28 per mcf due to the amalgamation with Mustang and Forte and an increased presence in northeast British Columbia and northern Alberta. For crude oil and NGL, transportation costs were down as much of the Trust's oil production is pipeline connected.

Financial instruments are used by the Trust to mitigate its exposure to future fluctuations in commodity prices. The Trust has entered into the following financial transactions:

Gas Contracts	Volume (gj/d)	Pricing Point	Strike Price (per gj)	Term
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
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$61.00 to US$73.05	Jan 1/07 to March 31/07
Costless collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to March 31/07
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

The net effect of these contracts and others, which have already expired, was a realized gain of $0.7 million and an unrealized gain of $4.6 million for the year ended December 31, 2006 (2005 – nil).

Subsequent to December 31, 2006, the Trust entered into the following financial transaction to mitigate its exposure to future fluctuations in commodity prices.

Gas Contract	Volume (gj/d)	Pricing Point	Strike Price (per gj)	Term
Costless collar	8,000	AECO	Cdn$6.50 to Cdn$8.00	April 1/07 to Oct 31/07

Royalties for the year were down 11% to $30.3 million from $33.9 million in 2005. Royalties as a percentage of revenue net of transportation were up to 18.4% compared to 17.9% in 2005. The increase was due to higher freehold and other royalties due to the amalgamation with Mustang and Forte offset by lower Crown royalties due to decreased natural gas prices in 2006. On September 21, 2006, the Alberta government announced it would discontinue its Alberta Royalty Tax Credit ("ARTC") program effective January 1, 2007.

ROYALTIES ($000s)	**2006**	2005
Crown	**21,897**	26,278
Freehold and other	**8,857**	8,118
Total gross royalties	**30,754**	34,396
ARTC	**(500)**	(491)
Net royalties	**30,254**	33,905

ROYALTY RATES (as a % of revenue, net of transportation expenses)	**2006**	2005
Crown	**13.3**	13.9
Freehold and other	**5.4**	4.3
Total gross royalties	**18.7**	18.2
ARTC	**(0.3)**	(0.3)
Net royalties	**18.4**	17.9

Operating costs for the year increased 26% from 2005 to $37.5 million or $10.87 per boe. The increase was due to a full year of operations as a Trust, as well as a reflection of high costs across the industry and the Trust's increased presence in northeast British Columbia and northern Alberta which tend to have higher operating costs. The Trust incurred higher operating costs in the second half of 2006 related to increased power and plant turnaround costs.

OPERATING COSTS	**2006**	2005
Operating costs ($000s)	**37,498**	29,704
Per boe ($)	**10.87**	8.63

Gross general and administrative expenses (G&A) increased 8% from 2005 to $14.3 million due to increased salaries and benefits and office space as a result of the transition into a Trust as well as increased compensation necessary to continue to attract and retain qualified personnel in a highly competitive market. Net G&A was $2.44 per boe, down 1% from 2005. The Trust incurred several budgeted, one-time costs in 2006 such as audit and tax services, annual filing costs and consulting services due to its transition into a Trust, as well as unbudgeted costs related to the federal government's October 31, 2006 announcement to apply a tax on distributions from publicly-traded income trusts. These budgeted and non-budgeted costs totaled $0.3 million or $0.10 per boe for the year (2005 – $3.3 million or $0.96 per boe). Also included in G&A are costs relating to documenting internal controls to meet regulatory requirements, which totaled $0.2 million or $0.06 per boe for the year.

G&A EXPENSES ($000s)	**2006**	2005
Gross G&A expenses	**14,252**	13,226
Capitalized G&A	**(3,903)**	(1,619)
Recoveries from joint operations		
Capital	**(867)**	(1,627)
Operating	**(1,083)**	(1,463)
Net G&A expenses	**8,399**	8,517

G&A EXPENSES ($/boe)		
Gross G&A expenses	**4.13**	3.84
Capitalized G&A	**(1.13)**	(0.47)
Recoveries from joint operations		
Capital	**(0.25)**	(0.47)
Operating	**(0.31)**	(0.43)
Net G&A expenses	**2.44**	2.47

Capitalized G&A per boe increased in 2006 to $1.13 per boe from $0.47 per boe in 2005 due to increased salaries due to a full year of operations as a Trust.

Unit-based compensation expense decreased 81% to $1.7 million from $8.6 million in 2005. In the third quarter of 2005, the Trust recognized $5.4 million of stock-based compensation related to the exercise of options resulting from the Plan of Arrangement.

Financial charges are comprised of bank debt interest, convertible debenture interest, amortization of deferred financing costs and accretion of convertible debenture liability. Financial charges were up 95% from 2005 due to increased interest rates and higher levels of debt due to lower commodity prices and production. A reconciliation of these charges follows:

FINANCIAL CHARGES ($000s)	2006	2005
Bank debt interest	**5,640**	5,357
Convertible debenture interest	**4,037**	–
Amortization of deferred financing costs	**539**	–
Accretion of convertible debenture liability	**209**	–
Total financial charges	**10,425**	5,357

Bank debt interest for the year increased 5% from 2005 due to a higher effective interest rate, offset by a decrease in the average bank debt outstanding. The decrease in average bank debt was due to the issuance of convertible debentures during the second quarter of 2006.

BANK DEBT	2006	2005
Average bank debt outstanding ($000s)	**106,739**	121,047
Effective annualized interest rate for the period (%)	**5.3**	4.4

Convertible debenture interest was $4.0 million for the year. The Trust 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 (DD&A) expenses increased $4.75 per boe to $26.55 per boe in 2006. The increase to $91.6 million from $75.1 million in 2005 was due to a full year of operations as a Trust. In addition, the DD&A rate increased due to a reduction in proved reserves at December 31, 2006. Accretion and DD&A expense on the asset retirement obligation increased due to the transition into a Trust and a revision to the Trust's liability estimate. Prior period DD&A has been restated to reflect the Trust's change in accounting policy for capitalized G&A expenses.

DD&A EXPENSE	2006	2005
DD&A expense ($000s)	**91,606**	75,058
DD&A rate ($/boe)	**26.55**	21.80

Write-down of oil and gas assets

The carrying value of the Trust's petroleum and natural gas property and equipment is limited to the amount calculated under the ceiling test at the balance sheet date. At December 31, 2006, the calculation indicated the carrying value of the Trust's petroleum and natural gas property and equipment was in excess of the amount calculated under the ceiling test. Accordingly, a write-down in the amount of $102.0 million (2005 – $56.2 million) was recorded. This write-down is primarily the result of downward revisions in the Trust's petroleum and natural gas reserves, as estimated by independent engineers as of December 31, 2006. The ceiling test calculation was based on benchmark reference prices adjusted for the Trust's quality and price differentials, discounted at an interest rate of 6.4% (2005 – 6.8%) over the estimated reserve life.

Tax Legislation Announcement

On October 31, 2006, the Federal Minister of Finance announced proposals (the "October 31, 2006 Proposals") to amend the *Tax Act* to apply a tax on distributions from publicly-traded income trusts. Under the October 31, 2006 Proposals, existing income and royalty trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. The Federal Minister of Finance has issued a Notice of Ways and Means Motion to Amend the *Tax Act*, but it is not known at this time if or when the proposal will be enacted by Parliament.

In simplified terms, under the proposed tax plan, distributions to unitholders, which are currently not subject to taxes or withholdings at the income trust level, will be subject to a new tax. Distributions to individual unitholders will be treated as dividends from a Canadian corporation, and will be eligible for the dividend tax credit. Income distributions to corporations resident in Canada will be eligible for full deduction as tax-free intercorporate dividends. Tax-deferred accounts (Registered Retirement Savings Plans, Registered Retirement Income Funds and Canadian Pension Funds) will continue to pay no tax on distributions received until funds are withdrawn. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. With tax to be applied at the Trust level, distributions will be reduced; however, the net impact on Canadian taxable investors is expected to be minimal as they will be able to take advantage of the dividend tax credit. By contrast, the impact on tax-deferred accounts and distributions to non-residents will be lower after-tax distributions as no tax credit will be available.

The government has also proposed to limit the growth of existing trusts by limiting new equity issues to 40% of that trust's October 31, 2006 market capitalization ("benchmark") for 2007, and an additional 20% of the benchmark for each of 2008, 2009, and 2010. The government also announced its intention to allow trusts to convert to a corporation on a tax–deferred basis, with no immediate tax impact for unitholders.

As none of the proposed rules has been substantively enacted into law, there has been no adjustment to future income taxes in regards to this announcement.

Given the grace period before existing trusts will be taxed, the Trust has an opportunity to examine its strategy, and, if warranted, modify it to provide the best possible return for unitholders. At the same time, unitholders have an opportunity to arrange their investments to minimize the impact of the proposed tax changes on their portfolios. The effect of the proposed tax changes on the Trust is yet to be determined. In particular, the Trust is evaluating the impact of the proposed measures on net income and cash flows, and the potential valuation of long-lived assets such as goodwill, all of which could be material.

Provision for Income Taxes

The Trust is a taxable entity under the *Tax Act*, 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 $71.6 million for the year primarily due to the estimated taxability of distributions and the write-down of oil and gas assets, as well as future tax rate reductions enacted by the federal and provincial governments during the second quarter of 2006.

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.

The following table summarizes the Trust's tax pools at December 31, 2006:

TAX POOLS ($000s)	2006
Canadian oil and gas property expenses (COGPE)	**21,213**
Canadian development expenses (CDE)	**98,643**
Canadian exploration expense (CEE)	**58,263**
Undepreciated capital costs (UCC)	**79,781**
Non-capital tax loss carry forwards	**75,842**
Unit issue costs	**3,674**
Total	**337,416**

Net Income (Loss) and Funds from Operations

Net loss increased to $99.5 million from $9.9 million in the prior year due to the write-down of the full cost pool under the ceiling test and the write-down of goodwill. The write-downs were offset by future tax recoveries due to the taxability of distributions and future tax rate reductions.

NET INCOME (LOSS)	2006	2005
Net income (loss) ($000s)	**(99,466)**	(9,851)
Per unit – basic ($)	**(2.07)**	(0.22)
Per unit – diluted ($)	**(2.07)**	(0.22)

Funds from operations decreased 28% year over year reflecting lower natural gas prices and higher operating and G&A expenses compared to 2005.

FUNDS FROM OPERATIONS	2006	2005
Funds from operations[1] ($000s)	**79,014**	110,391
Per unit – basic ($)	**1.65**	2.47
Per unit – diluted ($)	**1.51**	2.46
Funds from operations per boe ($)	**22.90**	32.07
Funds from operations as a percentage of gross sales (%)	**46.5**	56.4

[1] Funds from operations is calculated as cash from operating activities before the settlement of asset retirement obligations and changes in non-cash working capital relating to operating activities.

	Natural Gas ($/mcf)		Crude Oil and NGL ($/bbl)	
NETBACK ANALYSIS	2006	2005	2006	2005
Selling price (net of transportation)	**6.43**	8.66	**62.29**	62.57
Realized gain on commodity contracts	**(0.20)**	–	**1.43**	–
Royalties (net of ARTC)	**1.14**	1.55	**11.83**	12.99
Operating costs	**1.28**	1.48	**15.99**	7.97
Operating netback	**4.21**	5.63	**33.04**	41.61

NETBACK ANALYSIS (Barrels of oil equivalent) ($/boe)	2006	2005
Selling price (net of transportation)	**47.64**	55.02
Realized gain on commodity contracts	**(0.21)**	–
Royalties (net of ARTC)	**8.77**	9.85
Operating costs	**10.87**	8.63
Operating netback	**28.21**	36.54
G&A expenses	**2.44**	2.47
Bank debt interest	**1.63**	1.56
Convertible debenture interest	**1.17**	–
Current tax expense	**0.07**	0.44
Cash flow netback from operations	**22.90**	32.07

The total gas operating netback decreased 25% due to lower gas production and natural gas prices, which more than offset the declines in royalties and operating costs.

The total crude oil and NGL netback decreased 21% due a significant rise in operating costs due to increased crude oil production in northern Alberta. Lower royalties offset the higher operating costs.

Capital expenditures for the year aggregated $86.9 million. Drilling, completion, equipping and tie-in costs totaled $60.6 million for the drilling of 40 gas wells (25.8 net), 16 oil wells (7.3 net) and 13 dry holes (7.7 net). The Trust had an overall net drilling success ratio of 81%. In the fourth quarter of 2006, the Trust acquired three wells for $10.0 million. In 2007 the Trust has budgeted $62 million for capital expenditures to complete its drilling program.

At December 31, 2006, costs of $24.8 million (2005 – $16.3 million) related to unproven properties were excluded from the full cost pool.

CAPITAL EXPENDITURES SUMMARY ($000s)	2006	2005
Land and retention	**5,956**	3,682
Seismic	**3,214**	4,876
Drilling and completions	**41,285**	51,750
Well equipping and tie-in	**19,309**	19,264
Facilities and gas gathering	**2,450**	6,503
Property acquisitions, net of dispositions	**10,382**	741
Other, including capitalized G&A	**4,348**	1,578
Total capital expenditures	**86,944**	88,394
Wells drilled gross (net)	**69 (40.8)**	97 (67.1)

Trust Unit Information

For the years ending December 31, 2006 and 2005 the Trust had the following trust units and trust unit equivalents outstanding:

TRUST UNITS (000s)	2006	2005
Weighted average trust units	**47,279**	41,373
Exchangeable shares at exchange ratio	**739**	3,360
Trust units (basic)	**48,018**	44,733
Convertible debentures	**6,731**	–
Restricted and performance trust units	**350**	205
Trust units (diluted)	**55,099**	44,938

When calculating the diluted net loss per unit for the year ended December 31, 2006, the effect of the convertible debentures and the restricted and performance trust units are anti-dilutive and thus trust units (basic) have been used to calculate both basic and diluted net loss per unit amounts.

The funds from operations per unit calculations include the dilutive impact of both the convertible debentures and the restricted and performance trust units.

Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP")

The Trust has a Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") for eligible unitholders of the trust. On distribution payment dates, eligible DRIP unitholders may reinvest their cash distributions in additional trust units at a price that is 95% of the average market price for the corresponding pricing period. Eligible DRIP unitholders may also make optional cash payments on this date to purchase additional trust units at a price that is equal to the 10-day weighted average trading price of trust units. During the year, the Trust issued 4.2 million (2005 – 175,000) trust units from treasury for the DRIP which resulted in an increase to unitholders' capital of $34.1 million (2005 – $2.1 million).

LIQUIDITY AND CAPITAL RESOURCES

TOTAL CAPITALIZATION ($000s)	2006	2005
Working capital deficiency	**5,793**	18,284
Bank debt	**124,925**	136,359
Convertible debentures	**73,507**	–
Unit-based compensation (long-term)	**1,049**	528
Future income taxes (long-term)	**73,920**	146,876
Asset retirement obligations	**28,771**	24,774
Market value of trust units at year end	**287,275**	553,865
Total	**595,240**	880,686

GOODWILL

Under GAAP goodwill is assessed for impairment at least annually. The assessment is a two-step test under which the carrying value of goodwill is compared to its fair value. If the carrying value is greater than the fair value goodwill then the second step of the test is performed to determine the amount of impairment. Under the second step, the amount of the impairment is determined by deducting the fair value of the reporting unit's tangible assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and is charged to income in the period of the impairment. The Trust has assessed goodwill for impairment at December 31, 2006 and has recorded a write-down of $58.6 million (2005 – nil). The decrease in the value of goodwill is attributable to the write-down of the Trust's full cost pool. The following table reconciles the goodwill balance:

	($000s)
Balance December 31, 2004	**45,448**
Goodwill on Plan of Arrangement	**62,844**
Balance December 31, 2005	**108,292**
Write-down of goodwill	**(58,590)**
Balance December 31, 2006	**49,702**

ASSET RETIREMENT OBLIGATIONS

The Trust accrues asset retirement obligations which result 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 year, revisions were made to the liability to reflect changes in the inflation rate and the credit-adjusted risk-free rate. A reconciliation of the asset retirement obligations is provided below:

ASSET RETIREMENT OBLIGATIONS ($000s)	2006	2005
Balance, beginning of year	**24,774**	13,417
Liabilities incurred in the year	**800**	1,758
Liabilities assumed due to business combination – Forte	**-**	7,596
Liabilities assumed due to business combination – Mustang	**-**	5,019
Revisions	**3,571**	(135)
Liabilities released due to dispositions	**–**	(3,328)
Liabilities settled in the year	**(2,952)**	(1,306)
Accretion expense	**2,578**	1,753
Balance, end of year	**28,771**	24,774

Liquidity

For the year ended December 31, 2006, capital expenditures of $86.9 million, the settlement of asset retirement obligations of $3.0 million, a combined decrease to long-term debt, bank indebtedness, unit issue costs and working capital of $20.1 million and cash distributions, net of the distribution reinvestment plan ("DRIP"), of $40.6 million were funded by funds from operations of $79.0 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 2007 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 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 December 31, 2006
Debt portion on April 5, 2006	**73,298**
Accretion of non-cash interest	**209**
Debt portion, end of period	**73,507**
Equity portion	**1,702**
Total debentures, end of period	**75,209**

DISTRIBUTABLE CASH FROM OPERATIONS 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. For 2006 the payout ratio was 94% of funds from operations were distributed before DRIP, 50% 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.

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

Distributable cash from operations is calculated as funds from operations less discretionary amounts withheld for capital expenditures.

DISTRIBUTIONS ($000s)	2006	2005
Cash provided by operating activities	**75,505**	81,466
Settlement of asset retirement obligations	**2,952**	1,306
Changes in non-cash working capital relating to operating activities	**557**	27,619
Funds from operations	**79,014**	110,391
Cash used to fund capital expenditures	**(32,388)**	(73,717)
Distributable cash from operations[1]	**46,626**	36,674
Cash distributions declared and payable, including DRIP at December 31, 2006	**6,035**	6,595
Cash distributions paid in the period	**40,591**	30,079
Accumulated cash distributions paid and payable	**46,626**	36,674

[1] Distributable cash from operations will differ from cash distributions to unitholders on the Consolidated Statement of Cash Flows due to the timing of distribution announcements versus the cash payment of distributions.

SUSTAINABILITY OF DISTRIBUTIONS AND THE ASSET BASE

As an oil and gas trust, the Trust has a declining asset base and therefore relies on acquisitions and ongoing development activities to replace production and add additional reserves. Future oil and natural gas reserves are highly dependent on the successful exploitation of the asset base or the acquisition of new reserves. To the extent that the Trust is unsuccessful in these activities, cash available for distributions could be reduced.

Acquisitions and development activities may be funded internally by withholding a portion of cash flow or though external sources of capital such as debt or the issuance of equity. To the extent the Trust is required to withhold cash flow to finance these activities, the amount of cash available for distribution will be reduced. Should external sources of capital become limited or unavailable, the ability to make the necessary acquisitions and development expenditures to maintain or expand the Trust's asset base may be impaired and the amount of cash available for distribution will be reduced.

Distribution Policy

The amount of cash available for distribution is proposed by management and approved by the Board of Directors. Distribution levels are continually assessed with respect to forecasted funds from operations, debt levels and capital spending plans. The level of cash withheld can vary and is dependent upon numerous factors, the most significant of which are: the prevailing commodity price environment, current levels of production, debt obligations, the Trust's access to equity markets and the funding requirements for its development capital program. Although the Trust intends to continue to make cash distributions to unitholders, these distributions are not guaranteed.

On October 31, 2006, the Government of Canada announced proposed legislation that, if enacted, will impose a tax on the Trust of 31.5 % on cash distributions paid to unitholders. Income trusts that are publicly traded prior to November 2006 will not be impacted by this proposed legislation until 2011. If this proposed legislation is implemented, it will have an impact on distributable cash and the payout ratio.

Distributions Declared

DISTRIBUTIONS PER UNIT ($ per unit)	2006	2005
Distributions declared and payable per unit	**0.12**	0.15
Distributions declared and paid per unit	**1.44**	0.75
Accumulated distributions per unit	**1.56**	0.90

ACCUMULATED DISTRIBUTIONS ($000s)	Cash distributions	DRIP	Total
July distribution	6,301	–	6,301
August distribution	6,394	–	6,394
September distribution	6,419	–	6,419
October distribution	6,515	–	6,515
November distribution	4,450	2,072	6,522
December distribution	4,283	2,312	6,595
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
April distribution	3,543	3,428	6,971
May distribution	2,907	2,722	5,629
June distribution	2,987	2,716	5,703
July distribution	3,029	2,731	5,760
August distribution	3,004	2,795	5,799
September distribution	3,075	2,765	5,840
October distribution	2,784	3,120	5,904
November distribution	2,797	3,168	5,965
December distribution	2,992	3,043	6,035
2006 distributions	39,300	34,791	74,091
Balance December 31, 2006	**73,662**	**39,175**	**112,837**

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 year, the Trust incurred expenditures of $0.5 million (2005 – $1.0 million) 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 December 31, 2006, $1,750 (2005 – $10,000) remained outstanding. The related party transactions were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.

CONTRACTUAL OBLIGATIONS, COMMITMENTS AND GUARANTEES

The Trust has assumed various contractual obligations and commitments in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing cash requirements and in the analysis of future liquidity.

			Payments		
($000s)	**Total**	< 1 year	1-3 years	4-5 years	> 5 years
Firm transportation	**1,243**	500	743	–	–
Power contract	**1,221**	1,051	170	–	–
Office and vehicle leases	**12,205**	2,022	6,326	3,857	–
Total	**14,669**	3,573	7,239	3,857	–

CORPORATE RESTRUCTURING

On July 7, 2005, and in accordance with the Plan of Arrangement announced on May 3, 2005, Thunder Energy amalgamated with Mustang and Forte to form the Trust, two exploration companies, Clipper and Valiant, and a coalbed methane company, Ember.

The consideration for the Mustang acquisition was 1.1 trust units for each Mustang share resulting in 9.6 million trust units and 1.0 million exchangeable shares being issued. The value assigned to each trust unit was $7.60 based on the Thunder Energy share price at the time the Arrangement was announced. The value of the transaction was $161.2 million before the $24.5 million reduction for the conveyance of certain Mustang assets and liabilities to Clipper.

The consideration for the Forte acquisition was 0.35 trust units for each Forte share resulting in 6.5 million trust units and 1.0 million exchangeable shares being issued. The value assigned to each trust unit was $7.60 based on the Thunder Energy share price at the time the Arrangement was announced. The value of the transaction was $113.5 million, net of the $35.1 million reduction for the conveyance of certain Forte assets and liabilities to Valiant prior to the amalgamation.

In conjunction with the Plan of Arrangement, Thunder Energy transferred certain assets and undeveloped land to Ember and Clipper. At the time of the transaction the companies were related, and consequently, the assets were transferred to Ember and Clipper at the Thunder Energy carrying values which, for the assets acquired by Thunder Energy from Forte and Mustang, were fair market value. As part of the Arrangement, both Ember and Clipper paid $5.0 million to the Trust, which was accounted for as a reduction in capital in each entity.

FINANCIAL REPORTING UPDATE

For fiscal years beginning on or after October 1, 2006, the new Canadian Institute of Chartered Accountants ("CICA") Handbook section 3855 "Financial Instruments – Recognition and Measurement", section 1530 "Comprehensive Income" and section 3865 "Hedges" that deal with the recognition and measurement of financial instruments at fair value and comprehensive income will come into effect. The new standards are intended to harmonize Canadian standards with United States and international accounting standards. Management has assessed the impact of these pronouncements on the Trust's operating results and concluded they are not material.

FOURTH QUARTER OVERVIEW

Three Months Ended December 31	2006	2005	% Change
Financial ($000s, except per share data)			
Petroleum and natural gas sales	**40,879**	67,833	(40)
Funds from operations[1]	**18,530**	39,587	(53)
Per unit – basic ($)	**0.37**	0.86	(57)
Per unit – diluted ($)	**0.35**	0.85	(59)
Net loss	**(130,195)**	(25,433)	(412)
Per unit – basic ($)	**(2.61)**	(0.55)	(375)
Per unit – diluted ($)	**(2.61)**	(0.55)	(375)
Capital expenditures	**26,502**	24,456	(8)
Distributions declared	**17,904**	19,632	(9)
Distributions declared per unit ($)	**0.36**	0.45	(20)
Payout ratio[2] before DRIP	**97%**	50%	94
Payout ratio[2] after DRIP	**46%**	39%	18
Total debt including working capital deficiency	**204,225**	154,643	32
Weighted average units outstanding – basic	**49,863**	45,990	8
Weighted average units outstanding – diluted	**49,863**	46,332	8
Operations			
Daily production			
Natural gas (mcf/d)	**35,594**	40,489	(12)
Crude oil and NGL (bbls/d)	**3,346**	4,312	(22)
Barrels of oil equivalent (boe/d)	**9,279**	11,060	(16)
Average sale prices[3]			
Natural gas ($/mcf)	**6.65**	11.11	(40)
Crude oil and NGL ($/bbl)	**56.10**	62.64	(10)
Wells drilled – gross (net)			
Gas	**5 (1.6)**	23 (19.3)	
Oil	**2 (0.1)**	7 (2.2)	
Dry	**0 (0)**	18 (10.3)	
Total	**7 (1.7)**	48 (31.8)	

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

[1] Non-GAAP financial measure defined as cash provided by operating activities before changes in non-cash working capital relating to operating activities and the settlement of asset retirement obligations.

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

[3] Average sale price at the wellhead before commodity contracts gain or loss.

Results of Operations

Gross oil and gas revenues decreased 40% to $40.9 million in fourth quarter 2006 compared to 2005. The decrease is due to lower commodity prices (a 40% decrease in natural gas prices and a 10% decrease in crude oil and NGL prices) compared to the same period in 2005, as well as a 16% decline in overall production.

Commodity prices received by the Trust are based on the respective reference prices for both crude oil and natural gas adjusted for transportation and quality differentials, as applicable, and foreign exchange. The average price for crude oil and NGL in the quarter decreased 10% from fourth quarter 2005. The benchmark Edmonton posted oil price averaged $64.49 per bbl in the fourth quarter of 2006, a 9% decrease from fourth quarter 2005. The Trust's average natural gas price for the fourth quarter decreased 40% from the same period in 2005. The benchmark AECO gas price averaged $6.74 per mmbtu in the fourth quarter of 2006, a 41% decrease from fourth quarter 2005.

Transportation expenses for the fourth quarter increased 15% from 2005 to $1.8 million due to additional clean oil hauling charges in northern Alberta and Saskatchewan due to temporary pipeline closures and quotas.

Royalties as a percentage of revenue were 18.2% a 2% decrease from the fourth quarter of 2005 due to strong commodity pricing in 2005.

Operating costs increased 2% to $10.0 million or $11.76 per boe in fourth quarter 2006 from the same period in 2005. The Trust's operating costs are a reflection of high costs across the industry and the Trust's increased presence in northeast British Columbia and Northern Alberta which have higher operating costs. The Trust performed plant turnarounds which contributed to higher operating costs per boe as well as experiencing higher power costs.

Gross general and administrative expenses (G&A) were $4.2 million or $4.88 per boe in the fourth quarter of 2006. This is a 30% increase over 2005 due to increased compensation necessary to continue to attract and retain qualified personnel in a highly competitive market as well as unbudgeted costs related to the Federal government's October 31, 2006 announcement to apply a tax on distributions from publicly-traded income trusts. Also included in G&A are costs relating to documenting internal controls to meet regulatory requirements. For the fourth quarter of 2006 these costs totaled $0.1 million or $0.14 per boe.

Financial charges increased 83% over fourth quarter 2005 to $3.4 million from $1.9 million in 2005 due to higher debt comprised of bank debt and convertible debentures as well as higher interest rates.

Interest expense on bank debt decreased 5% over fourth quarter 2005 to $1.8 million due to lower bank debt in the quarter offset by higher interest rates.

Convertible debenture interest was $1.4 million for the fourth quarter 2006. 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.

FINANCIAL CHARGES (Three months ended December 31) ($000s)	**2006**	2005
Bank debt interest	**1,757**	1,856
Convertible debenture interest	**1,383**	–
Amortization of deferred financing costs	**191**	–
Accretion of convertible debenture liability	**72**	–
Total financial charges	**3,403**	1,856

Depletion, depreciation and accretion (DD&A) expenses increased to $21.8 million or $25.56 per boe up $3.88 per boe from the fourth quarter of 2005. The DD&A rate increased due to a reduction in proved reserves at December 31, 2006. Accretion and DD&A expense on asset retirement obligations increased due to revisions made to the Trust's liability estimate for changes to the inflation rate and the credit-adjusted risk-free rate.

Write-down of oil and gas assets

The carrying value of the Trust's petroleum and natural gas property and equipment is limited to the amount calculated under the ceiling test at the balance sheet date. At December 31, 2006, the calculation indicated the carrying value of the Trust's petroleum and natural gas property and equipment was in excess of the amount calculated under the ceiling test, accordingly, a write-down in the amount of $102.0 million (2005 – $56.2 million) has been recorded. This write-down is primarily the result of downward revisions in the Trust's petroleum and natural gas reserves, as estimated by independent engineers as of December 31, 2006. The ceiling test calculation was based on benchmark reference prices adjusted for the Trust's quality and transportation differentials discounted at an interest rate of 6.4% (2005 – 6.8%) over the estimated reserve life.

Goodwill

The Trust has assessed goodwill for impairment at December 31, 2006 and has recorded a write-down of $58.6 million (2005 – nil) during the fourth quarter.

Unit-based compensation expense decreased 47% to $0.4 million in the fourth quarter 2006 from the same period in 2005. The compensation liability was based on the December 31, 2006 unit closing price of $5.67, distributions of $0.12 per unit per month for the quarter, and management's estimate of the number of RTUs and PTUs to be issued on maturity.

Funds from operations decreased 53% to $18.5 million in the fourth quarter 2006 over the same periods in 2005 reflecting lower commodity prices and production as well as increased operating and G&A expenses.

Net loss

The Trust experienced a loss of $130.2 million in the fourth quarter 2006 due to a write-down of $102.0 million of the full cost pool due to a decline in the Trust's reserves as well as a $58.6 million write-down of goodwill, offset by a future tax recovery of $35.7 million related to the tax effect of the write-downs as well as the taxability of distributions and future tax rate reductions.

QUARTERLY INFORMATION

($000s, except per unit data)	Q1	Q2	Q3	Q4
2005				
Petroleum and natural gas sales	29,350	32,729	65,866	67,833
Funds from operations[2]	16,599	19,168	35,037	39,587
Per unit – basic ($)	0.64	0.74	0.79	0.86
Per unit – diluted ($)	0.63	0.73	0.79	0.85
Net income	3,243	4,621	7,718	(25,433)
Per unit – basic ($)	0.13	0.18	0.18	(0.55)
Per unit – diluted ($)	0.12	0.18	0.17	(0.55)
Daily production				
Natural gas (mcf/d)	38,174	37,978	44,680	40,489
Oil and NGL (bbls/d)	1,145	1,190	4,128	4,312
Barrels of oil equivalent (boe/d)	7,508	7,520	11,574	11,060
Average sale prices[1]				
Natural gas ($/mcf)	6.74	7.41	9.13	11.11
Oil and NGL ($/bbl)	48.67	49.81	69.90	62.64
Capital expenditures	32,579	10,131	21,228	24,456
2006				
Petroleum and natural gas sales	**46,242**	**41,504**	**41,352**	**40,879**
Funds from operations[2]	**22,813**	**18,894**	**18,777**	**18,530**
Per unit – basic ($)	**0.50**	**0.40**	**0.39**	**0.37**
Per unit – diluted ($)	**0.49**	**0.36**	**0.36**	**0.35**
Net income	**3,725**	**18,744**	**8,260**	**(130,195)**
Per unit – basic ($)	**0.08**	**0.39**	**0.17**	**(2.61)**
Per unit – diluted ($)	**0.08**	**0.36**	**0.17**	**(2.61)**
Daily production				
Natural gas (mcf/d)	**36,572**	**34,001**	**34,178**	**35,594**
Oil and NGL (bbls/d)	**3,910**	**3,640**	**3,532**	**3,346**
Barrels of oil equivalent (boe/d)	**10,005**	**9,307**	**9,229**	**9,279**
Average sale prices[1]				
Natural gas ($/mcf)	**7.40**	**5.83**	**5.79**	**6.65**
Oil and NGL ($/bbl)	**57.34**	**67.21**	**68.51**	**56.10**
Capital expenditures	**18,183**	**21,530**	**20,729**	**26,502**

1 Average sale price at the wellhead before commodity contracts gain or loss.

2 Funds from operations is calculated as cash from operating activities before the settlement of asset retirement obligations and changes in non-cash working capital relating to operating activities.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's management as appropriate to allow timely decisions regarding required disclosure. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, the Trust's disclosure controls and procedures for the years ended December 31, 2006 and 2005, are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made known to them by others within those entities. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S CONCLUSION ON THE DESIGN OF INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements together with other financial information for external purposes in accordance with Canadian GAAP. The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting related to the Trust, including its consolidated subsidiaries.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by the Trust are disclosed in Note 1 of the consolidated financial statements for the periods ended December 31, 2006 and 2005. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to the estimated amounts that differ materially from current estimates. The following discussion helps to assess the critical accounting policies and practices of the Trust and the likelihood of materially different results being reported.

Oil and Gas Accounting – Reserves Determination

Under the National Instrument 51-101 ("NI 51-101") "proved" reserves are defined as those reserves that can be estimated with a high degree of certainty to be recoverable. The level of certainty should result in at least 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

"Proved plus probable" reserves are the most likely case and are based on a 50% certainty that they will equal or exceed the reserves estimated. The new standard provides for a more conservative evaluation of proved and probable reserves, particularly on new wells where production history has not yet been established.

The Trust follows the full cost method of accounting for its oil and gas activities, as described in Note 1 to the consolidated financial statements. Full cost accounting depends on the estimated proved reserves that the Trust believes are recoverable from its oil and gas properties. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Reserve estimates are based on current production forecasts, prices and economic conditions. The Trust's reserves are evaluated by an independent engineering firm (GLJ Petroleum Consultants).

Reserve estimates are critical to many of the Trust's accounting estimates, including:

- Calculating unit-of-production depletion rates and asset retirement obligations. Proved reserve estimates are used to determine rates that are applied to each unit-of-production in calculating depletion expense.
- Assessing the Trust's oil and gas assets for possible impairment. Estimated future undiscounted cash flows are determined using proved reserves. The criteria used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

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

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

Ceiling Test

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. Impairment is recognized when the carrying amount is greater than the undiscounted future net revenues, at which time assets are written down to the fair value of proved and probable reserves plus the cost of unproven properties, net of impairment allowances. Fair value is determined by discounting expected future product prices and costs.

Depletion and Depreciation

The Trust uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproven properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense. Certain costs related to unproven properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation or, if significant, disclosed separately on the consolidated statement of loss.

Goodwill

Goodwill represents the excess of the purchase price on corporate acquisitions over the fair value of net assets acquired. Goodwill is assessed for impairment at least annually. If it is determined that the fair value of the assets and liabilities is less than the book value at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment.

Asset Retirement Obligations

The Trust records the fair value of an asset retirement obligations as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using a unit-of-production method over estimated proved reserves. Subsequent to the initial measurement of the asset retirement obligations, the obligations are adjusted at the end of each period to reflect the passage of time (accretion) and changes in the estimated future cash flows underlying the obligation.

Trust Unit Incentive Plans

The Trust approved a restricted unit plan and a performance unit incentive plan (the "Plans"). Under the terms of the Plans, both restricted and performance units ("RTUs" and "PTUs") may be granted to directors, officers, employees, consultants and service providers (the "Plan Participants") to the Trust and any of its subsidiaries.

Compensation expense associated with the Plans is granted in the form of RTUs and PTUs and is determined based on the intrinsic value of the trust units at each period end. The intrinsic value method is used as Plan Participants may be paid, at management's discretion, in cash or new units issued from treasury. This valuation incorporates the period end trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying trust unit incentive price. In addition, compensation expense is amortized over the vesting period of the incentive plan with a corresponding increase or decrease in liabilities. Classification between current and long-term unit-based compensation liability is dependent upon expected payout dates.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from the liability estimated or recorded.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates including estimates of revenues, royalties and production costs as at a specific reporting date but for which actual revenues and costs have not yet been received, and estimates on capital projects which are in progress or recently completed where actual costs have not been received at a specific reporting date.

The Trust ensures that the individuals with the most knowledge of the activity are responsible for the estimate. These estimates are then reviewed for reasonableness and past estimates are compared to actual results in order to make informed decisions on future estimates.

RISKS AND UNCERTAINTIES

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Trust will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the cost associated with encountering various drilling conditions such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of the Trust depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Trust will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Trust may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Trust. World prices for crude oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world crude oil and natural gas prices, leading to a reduction in the volume of the Trust's oil and gas reserves. The Trust might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Trust's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Trust are in part determined by the borrowing base of the Trust. A sustained material decline in prices from historical average prices could limit the Trust's borrowing base; therefore, reducing the bank credit available to the Trust, and could require that a portion of any of the Trust's existing bank debt be repaid.

In addition to establishing markets for its crude oil and natural gas, the Trust must also successfully market its crude oil and natural gas to prospective buyers. The marketability and price of crude oil and natural gas, which may be acquired or discovered by the Trust, will be affected by numerous factors beyond its control. The Trust will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by the Trust. The ability of the Trust to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Trust will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas, and many other aspects of the crude oil and natural gas business. The Trust has limited direct experience in the marketing of crude oil and natural gas.

The Trust is also exposed to currency exchange risk arising from the fact that prices for crude oil and, to a lesser degree, natural gas, are determined in international markets, usually in US dollars. As a result, the amount received by the Trust may depend on the strength of the Canadian dollar versus the US dollar. The Trust has the ability to hedge its currency exposure to manage currency fluctuations but currently has no hedges of this type in place.

Substantial Capital Requirements, Liquidity

The Trust anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of crude oil and natural gas reserves in the future. If the Trust's revenues or reserves decline, the Trust may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Trust. Moreover, future activities may require the Trust to alter its capitalization significantly. The inability of the Trust to access sufficient capital for its operations could have a materially adverse effect on the Trust's financial condition, results of operations or prospects.

The Trust's lenders have been provided with security over substantially all of the assets of the Trust. If the Trust becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose or sell the Trust's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Trust's lenders and other creditors and only the remainder, if any, would be available to the Trust.

An increase in interest rates would result in an increase in the amount the Trust pays to service debt, which could result in a decrease in distributions to unitholders, as well as impact the market price of trust units.

Competition

The Trust actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel resources than the Trust. The Trust's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Certain of the Trust's customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect the Trust's ability to sell or supply oil or gas to these customers in the future. The Trust's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators, and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and provincial, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities, and potentially increased capital expenditures and operating costs. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Trust's financial condition, results of operations or prospects.

Insurance

The Trust's involvement in the exploration for and development of oil and gas properties may result in the Trust becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Trust has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, the Trust may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Trust. The occurrence of a significant event that the Trust is not fully insured against, or the insolvency of the insurer of such event, could have a materially adverse effect on the Trust's financial position, results of operations or prospects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change. Canada has ratified the Kyoto Protocol established thereunder. Annex B parties to the Kyoto Protocol, which includes Canada, are required to establish legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other so-called "greenhouse gases". The Trust's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject the Trust to legislation in Canada regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation to set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future Canadian federal legislation, together with provincial emission reduction requirements, such as those proposed in the Climate Change and Emissions Management Act (Alberta), may require the reduction of emissions or emissions intensity from the Trust's operations and facilities. The direct and indirect costs of complying with these emissions regulations may adversely affect the business of the Trust.

Reserve Replacement

The Trust's future crude oil and natural gas reserves and production, and cash flows to be derived therefrom, are highly dependent on the Trust successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Trust may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Trust's reserves will depend not only on the Trust's ability to develop any properties it may have from time to time, but also on its ability to develop any producing properties or prospects. There can be no assurance that the Trust's future exploration and development efforts will result in the discovery of additional commercial accumulations of crude oil and natural gas.

Reliance on Operators and Key Employees

To the extent the Trust is not the operator of its oil and gas properties, the Trust will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Trust will be largely dependent upon the performance of its management and key employees. The Trust does not have any key man insurance policies; therefore, there is a risk that the death or departure of any member of management or any key employee could have a materially adverse effect on the Trust.

Permits and Licenses

The operations of the Trust may require licenses and permits from various governmental authorities. There can also be no assurance that the issuer will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Additional Funding Requirements

The Trust's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Trust may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Trust to forfeit interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Trust's revenue from its reserves decreases as a result of low crude oil and natural gas prices or otherwise, it will affect the Trust's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Trust's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Trust.

From time to time, the Trust may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Trust's debt levels above industry standards. Neither the Trust's articles nor its by-laws limit the amount of indebtedness that the Trust may incur. The level of the Trust's indebtedness from time to time could impair the Trust's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Title to Properties

Although title reviews are done according to industry standards prior to the purchase of most crude oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Trust's claim which could result in a reduction of the revenue received by the Trust.

Aboriginal Claims

Aboriginal people have claimed aboriginal title and rights to portions of western Canada. The Trust is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on the Trust and its operations.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of crude oil and natural gas to the Trust or to the operators, and the delays by operators in remitting payment to the Trust, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustments for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Trust in a given period and expose the Trust to additional third party credit risks.

Changes in Legislation

The return on an investment in securities of the Trust is subject to changes in Canadian federal and provincial tax laws and government incentive programs and there can be no assurance that such laws or programs will not be changed in a manner that adversely affects the Trust or the holding and disposing of the securities of the Trust.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby, reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Trust.

Return of Capital

Trust units will have no value when Thunder's oil and gas properties can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a combination of return of unitholders' initial investment and return on unitholders' initial investment.

Unitholders have a limited right to require the Trust to repurchase their trust units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to limitations.

Nature of Trust Units

Trust units do not represent a traditional investment in the oil and natural gas sector and should not be viewed as shares in Thunder Energy Inc. or its subsidiaries. Trust units represent a fractional interest in the Trust. As holders of trust units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets are investments and notes receivable from Thunder Energy Inc. The price per trust unit is a function of anticipated distributable cash from operations, underlying assets and management's ability to effect long-term growth in value. The market price of the trust units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the Trust's ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the trust units.

The trust units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on nor intend to carry on the business of a trust company.

Exchangeable Shares

An investment in exchangeable shares should be considered speculative due to the fact that adjustments to the exchange ratio are made assuming reinvestment of distributions or dividends, as applicable, at the prevailing market price of a trust unit at the time at which any such distributions are made on the trust units or any such dividends are paid on the exchangeable shares. As a result, the cumulative return on an investment in exchangeable shares may be higher or lower than that on an investment in trust units over a comparable period.

Unitholder Limited Liability

The Trust Indenture provides that no unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a unitholder resulting from or arising out of such unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The Trust's operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the unitholders for claims.

In addition the Income Trust Liability Act (Alberta) was proclaimed in force in Alberta on June 30, 2004. The Income Trust Liability Act (Alberta) provides that the beneficiary of a trust that is (a) created by a trust instrument governed by the laws of Alberta, and (b) a reporting issuer as defined in the Securities Act (Alberta), is not liable as a beneficiary for any act, default, obligation or liability of the trustee.

Mutual Fund Trust Status

It is intended that the Trust qualify at all times as a mutual fund trust for the purposes of the *Tax Act.* The Trust may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and its unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- where at the end of any month a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP") or deferred profit sharing plan (collectively, "Exempt Plans") holds units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the *Tax Act* equal to one percent of the fair market value of the units at the time such units were acquired by the Exempt Plan. An RRSP or RRIF holding units that are not qualified investments would become taxable on income attributable to the units while they are not qualified investments (including the entire amount of any capital gain arising on a disposition of the non-qualified investment). RESP's which hold units that are not qualified investments may have their registration revoked by the CRA.
- the Trust would be required to pay a tax under Part XII.2 of the *Tax Act.* The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain unitholders, including non-resident persons and residents of Canada who are exempt from Part I tax.
- the Fund would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws; and
- units would become taxable Canadian property. As a result, non-resident unitholders would be subject to Canadian income tax on any gains realized on a disposition of units held by them, subject to relief under an applicable tax convention. In addition, the Trust may take certain measures in the future to the extent that it believes such measures are necessary to ensure it maintains its status as a mutual fund trust. These measures could be adverse to certain holders of units.

Non-resident Ownership of Units

In order for the Trust to maintain its status as a mutual fund trust under the *Tax Act*, the Trust must not be established or maintained primarily for the benefit of non-residents of Canada ("non-residents") within the meaning of the *Tax Act.* Proposed amendments to the *Tax Act* originally published by the Minister of Finance (Canada) on March 22, 2004, were to provide that after December 31, 2004, the Trust must continuously ensure that not more than 50% of its issued units are held by non-residents of Canada or partnerships (other than "Canadian partnerships" as defined in the *Tax Act*). In December 2004 the Minister of Finance announced that these Proposed Amendments were not being included in draft legislation and that further discussions would be pursued with the private sector concerning the appropriate Canadian tax treatment of non-residents investing in resource property through mutual fund trusts. The Trust Indenture provides that at no time may non-residents be the beneficial owners of more than 49% of the trust units. If at any time the Trust or its administrator, Thunder Energy Inc., become aware that the activities of the Trust and/or ownership of units by non-residents may threaten the status of the Trust under the *Tax Act* as a "mutual fund trust", the Trust, by or through Thunder Energy Inc. on the Trust's behalf, is authorized to take such action as may be necessary in the opinion of Thunder Energy Inc. to maintain the status of the Trust as a "mutual fund trust".

Income Tax Matters

Generally, income trusts, including the Trust, involve significant amounts of intercompany debt, royalties or similar instruments, generating substantial interest expense or other deductions which serve to reduce taxable income and income tax payable. Although the Trust is of the view that all expenses claimed by the Trust and its subsidiaries will be reasonable and deductible and that the cost amount and capital cost allowance claims of such entities' depreciable properties will have been correctly determined, there can be no assurance that the taxation authorities will not seek to challenge the amount of interest expense and other deductions. If such a challenge were to succeed, it could materially adversely affect the amount of distributions available to the Trust. The Trust believes that the interest expense inherent in the structure of the Trust is supportable and reasonable.

Maintenance of Distributions

The Trust adds to its crude oil and natural gas reserves primarily through development and acquisitions with only a small percentage of the capital directed to exploration. As a result, future crude oil and natural gas reserves are highly dependent on the Trust's operating entities' success in exploiting existing properties and acquiring additional reserves. The Trust distributes a portion of its net cash flow to unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional trust units, become limited or unavailable on commercially reasonable terms, the Trust's operating entities' ability to make the necessary capital investments to maintain or expand crude oil and natural gas reserves will be impaired. To the extent that the Trust's operating entities are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to unitholders will be reduced. Additionally, the Trust cannot guarantee that it will be successful in developing additional reserves or acquiring additional reserves on terms that meet its investment objectives. Without these reserve additions, the Trust's reserves will deplete and as a consequence, either production from, or the average reserve life of, the Trust's properties will decline. Either decline may result in a reduction in the value of trust units and in a reduction in cash available for distributions to unitholders.

Assessments of Value of Acquisitions

Acquisitions of oil and gas issuers and oil and gas assets are typically based on engineering and economic assessments made by independent engineers and the Trust's own assessments. Both these assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Trust's control. In particular, the prices of and markets for crude oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that the Trust uses for its year-end reserve evaluations.

Accounting Write-Downs as a Result of GAAP

Canadian GAAP requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the consolidated financial statements of the Trust. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavorably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Trust's units.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flow from reserves. If net capitalized costs exceed the estimated recoverable amounts, the Trust would have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Third Party Credit Risk

The Trust is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Trust, such failure could have a materially adverse effect on the Trust and its cash flow.

THUNDER ENERGY TRUST

FINANCIALS

MANAGEMENT'S REPORT

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the consolidated financial statements and other financial operating data contained elsewhere in the report. The accompanying consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgment, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and reflect fairly the Trust's financial position, results of operations and cash flow, within reasonable limits of materiality and within the framework of the accounting policies as outlined in the notes to the consolidated financial statements.

Management has established and maintained a system of internal control which is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

External auditors have examined the consolidated financial statements. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported operating results and financial condition of the Trust.

The Audit Committee of the Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Stuart J. Keck
President and Chief Executive Officer

Brent T. Kirkby
Vice President, Finance and Chief Financial Officer

AUDITORS' REPORT

To the Unitholders of Thunder Energy Trust

We have audited the consolidated balance sheets of Thunder Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of loss and accumulated earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

March 2, 2007

CONSOLIDATED BALANCE SHEETS

As at December 31 ($000s)	2006	2005
Assets (Note 5)		
Current		
Accounts receivable (Note 14)	**$ 35,470**	$ 49,810
Commodity contracts (Note 12)	**4,558**	–
Prepaid expenses	**3,381**	1,219
	43,409	51,029
Deferred financing costs (Note 7)	**2,887**	–
Property and equipment (Note 3)	**558,372**	658,069
Goodwill (Note 4)	**49,702**	108,292
	$ 654,370	$ 817,390
Liabilities and Unitholders' Equity		
Current		
Bank indebtedness	**$ 2,931**	$ 4,409
Distributions payable	**6,035**	6,595
Accounts payable and accrued liabilities (Note 14)	**38,237**	57,542
Future income taxes (Note 11)	**1,395**	–
Unit-based compensation (Note 9)	**604**	767
	49,202	69,313
Bank debt (Note 5)	**124,925**	136,359
Convertible debentures (Note 6)	**73,507**	–
Unit-based compensation (Note 9)	**1,049**	528
Asset retirement obligations (Note 8)	**28,771**	24,774
Future income taxes (Note 11)	**73,920**	146,876
	351,374	377,850
Commitments and contingencies (Note 16)		
Unitholders' equity		
Unitholders' capital (Note 9)	**446,652**	411,341
Equity component of convertible debentures (Note 6)	**1,702**	–
Contributed surplus (Note 9)	**3,025**	3,025
Accumulated earnings (deficit)	**(148,383)**	25,174
	302,996	439,540
	$ 654,370	$ 817,390

See accompanying notes

On behalf of the Board:

Douglas A. Dafoe
Director

John Clark
Director

CONSOLIDATED STATEMENTS OF LOSS AND ACCUMULATED EARNINGS (DEFICIT)

Years ended December 31 ($000s, except per unit data)	2006	2005
Revenues		
Petroleum and natural gas sales	**$ 169,977**	$ 195,778
Royalties, net of ARTC	**(30,254)**	(33,905)
Transportation expenses	**(5,615)**	(6,383)
Petroleum and natural gas sales, after royalties and transportation	**134,108**	155,490
Realized net gain on commodity contracts (Note 12)	**724**	–
Unrealized net gain on commodity contracts (Note 12)	**4,558**	–
Petroleum and natural gas sales, net	**139,390**	155,490
Expenses		
Operating	**37,498**	29,704
General and administrative (Note 15)	**8,399**	8,517
Unit-based compensation (Note 9)	**1,659**	8,582
Financial charges (Note 7)	**10,425**	5,357
Write-down of property and equipment (Note 3)	**101,984**	56,243
Write-down of goodwill (Note 4)	**58,590**	–
Depletion, depreciation and accretion	**91,606**	75,058
	310,161	183,461
Loss before income taxes	**(170,771)**	(27,971)
Income tax recovery (Note 11)	**(71,305)**	(18,120)
Net loss for the year	**(99,466)**	(9,851)
Accumulated distributions (Note 10)	**(74,091)**	(38,746)
Accumulated earnings (deficit)		
Beginning of year	**25,174**	73,771
End of year	**$ (148,383)**	$ 25,174
Net loss per unit (Note 9)		
Basic and diluted	**$ (2.07)**	$ (0.22)

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 ($000s)	2006	2005
Operating Activities		
Net loss for the year	**$ (99,466)**	$ (9,851)
Add items not requiring cash:		
Amortization of deferred financing costs (Note 7)	**539**	–
Accretion on convertible debenture liability (Note 7)	**209**	–
Unit-based compensation	**1,659**	8,582
Unrealized net gain on commodity contracts	**(4,558)**	–
Depletion, depreciation and accretion	**91,606**	75,058
Write-down of property and equipment (Note 3)	**101,984**	56,243
Write-down of goodwill (Note 4)	**58,590**	–
Future income taxes (Note 11)	**(71,549)**	(19,641)
Settlement of asset retirement obligations	**(2,952)**	(1,306)
Changes in non-cash working capital relating to operating activities (Note 13)	**(557)**	(27,619)
Cash provided by operating activities	**75,505**	81,466
Financing Activities		
Issue of units for cash, net of costs	**(62)**	11,398
Convertible debenture issue costs (Note 7)	**(3,426)**	–
Proceeds on convertible debentures (Note 6)	**75,000**	–
Increase (decrease) in bank indebtedness	**(1,478)**	2,841
Increase (decrease) in bank debt	**(11,434)**	53,463
Cash distributions (Note 10)	**(40,591)**	(30,079)
Cash received on Plan of Arrangement (Note 2)	**–**	10,000
Cash provided by financing activities	**18,009**	47,623
Investing Activities		
Expenditures on property and equipment	**(86,944)**	(88,394)
Assumption of bank indebtedness (Note 2)	**–**	(49,728)
Changes in non-cash working capital relating to investing activities (Note 13)	**(6,570)**	9,012
Cash used in investing activities	**(93,514)**	(129,110)
Net change in cash position	**–**	(21)
Cash – beginning of year	**–**	21
– end of year	**$ –**	$ –

See accompanying notes

NOTES

TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2006 and 2005

Thunder Energy Trust (the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The principal undertaking of the Trust is to indirectly explore for, develop and hold interest in petroleum and natural gas properties through investments in securities of subsidiaries. Thunder Energy Inc. and its subsidiaries carry on the business of the Trust and directly own the petroleum and natural gas properties and assets related thereto. The Trust owns, directly and indirectly, 100% of the common shares (excluding the outstanding exchangeable shares) of Thunder Energy Inc.

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 coal bed 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 conversion of Thunder Energy to a trust has been accounted for on a continuity of interest basis. Accordingly, the consolidated financial statements for 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. The consolidated financial statements for the year ended December 31, 2005 reflect the results of operations and cash flows of Thunder Energy and its subsidiaries for the period January 1 to July 6, 2005 and the results of operations and cash flows of the Trust and its subsidiaries for the period July 7 to December 31, 2005. Due to the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be directly comparable.

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of Business and Basis of Presentation

The Trust is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements of the Trust have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated. Specifically, the amounts recorded for depletion, depreciation and accretion of oil and natural gas properties and equipment and asset retirement obligations are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries. All intercompany transactions and balances have been eliminated.

Petroleum and Natural Gas Properties and Gas Plants and Related Facilities

The Trust follows the full cost method of accounting whereby all costs associated with the acquisition of and the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in one Canadian cost centre and charged to income as set out below. Such costs include lease acquisition, drilling, equipping, geological and geophysical costs and overhead expenses directly related to exploration and development activities. Certain salaries, benefits and general and administrative expenses related to acquisition, exploration and development activities are also included in the full cost pool.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion and Depreciation

Depletion of petroleum and natural gas properties is provided on accumulated costs and future development costs associated with proved undeveloped reserves using the unit-of-production method based on estimated gross proved petroleum and natural gas reserves, as determined by independent engineers. For purposes of the depletion calculation, proved petroleum and natural gas reserves are converted to a common unit of measure on the basis of one barrel of oil or liquids being equal to six mcf of natural gas. Costs of acquiring and evaluating unproven properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Depreciation of gas plants and related facilities is calculated on a straight-line basis over their estimated useful lives of 15 years.

The Trust records other assets at cost and provides depreciation on the declining balance method at rates varying from 20% to 100% per annum which is designed to amortize the cost of the assets over their estimated useful lives.

Impairment

The Trust evaluates its petroleum and natural gas assets in each reporting period to determine that the costs are recoverable and do not exceed the fair value of the properties. If the sum of the undiscounted cash flows expected from the production of proved reserves plus the cost (less any impairment) of unproven properties exceeds the carrying value of the petroleum and natural gas assets plus future development costs associated with proved undeveloped reserves, the costs are considered recoverable. Cash flows are calculated based on third-party quoted forward prices, adjusted for the Trust's contract prices and quality differentials. If the carrying value of the petroleum and natural gas assets is not considered to be recoverable, an impairment loss is recognized to the extent that the carrying value plus future development costs associated with proved undeveloped reserves exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves. The cash flows are estimated using future product prices and costs and then discounted.

The costs of unproven properties are excluded from the ceiling test calculation and subject to a separate impairment test.

Asset Retirement Obligations

The Trust records the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and depleted and depreciated using a unit-of-production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligations, the obligations are adjusted at the end of each period to reflect the passage of time (accretion) and changes in the estimated future cash flows underlying the obligation.

Goodwill

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of net assets acquired; thereafter, goodwill is assessed for impairment at least annually. If the fair value of the reporting unit is less than the carrying amount, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's tangible assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment. Due to the nature of the Trust's operations, the Trust has only one reporting unit.

Joint Interest Operations

A portion of the Trust's petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Revenue Recognition

Revenue from the sale of petroleum and natural gas is recognized during the month when title passes.

Trust Unit Incentive Plans

The Trust has established incentive plans for employees, officers, directors, consultants and other service providers. Compensation expense associated with the unit incentive plans is granted in the form of restricted trust units ("RTUs") and performance trust units ("PTUs") and is determined based on the intrinsic value of the trust units at each period end. The intrinsic value method is used as Plan Participants may be paid, at management's discretion, in cash or new units issued from treasury. This valuation incorporates the period end trust unit price, the number of RTUs and PTUs outstanding at each period end, and certain management estimates. As a result, large fluctuations, even recoveries, in compensation expense may occur due to changes in the underlying trust unit incentive price. In addition, compensation expense is amortized over the vesting period of the incentive plans with a corresponding increase or decrease in liabilities. Classification between current and long-term unit-based compensation liability is dependent upon the expected payout date. The Trust has not incorporated an estimated forfeiture rate for RTUs and PTUs that will not vest; rather, the Trust accounts for actual forfeitures as they occur.

Per Unit Amounts

Per unit amounts are calculated using the weighted average number of trust units outstanding during the period. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the period. Diluted per unit amounts also include exchangeable shares and convertible debentures using the "if-converted" method, whereby it is assumed the conversion of the exchangeable securities and convertible debentures occurs at the beginning of the reporting period (or at the time of issuance if later).

Income Taxes

The Trust is a mutual fund trust for purposes of the *Tax Act* (Canada), and is subject only to statutory income taxes on taxable income not distributed to unitholders. There is no recognition of future income tax assets or liabilities on temporary differences within the Trust; however, the asset and liability method of accounting for income taxes is followed within the subsidiaries of the Trust. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change becomes substantively enacted.

Hedging

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. The Trust does not enter into financial instruments for trading or speculative purposes. 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, its risk management objective and strategy, the method of assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the hedging derivative is assessed on an ongoing basis to ensure that the derivative is highly effective in offsetting changes in fair value of the hedged items. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, are recognized as hedging gains or losses when the sale of hedged production occurs. In the event that a designated hedged item ceases to exist, any realized or unrealized gain or loss on such derivative commodity instrument is recognized in income immediately. If the hedge relationship is terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continue to be deferred and recognized when they are realized.

Comparative Amounts

Certain comparative amounts have been reclassified to conform to the presentation adopted for the current year.

2. PLAN OF ARRANGEMENT

On July 7, 2005, and in accordance with the Plan of Arrangement announced on May 3, 2005, Thunder Energy amalgamated with Mustang and Forte to form the Trust, two exploration companies, Clipper and Valiant, and a coalbed methane company, Ember. The amalgamation was accounted for as a business combination with Thunder Energy being deemed the acquirer of Mustang and Forte, net of the Valiant assets. Consequently the Trust has 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 consideration for the Mustang acquisition was 1.1 trust units for each Mustang share resulting in 9.6 million trust units and 1.0 million exchangeable shares being issued. The value assigned to each trust unit was $7.60 based on the Thunder Energy share price at the time the Arrangement was announced. The value of the transaction was $161.2 million before the $24.5 million reduction for the conveyance of certain Mustang assets and liabilities to Clipper. The results of Mustang have been included in the consolidated financial statements commencing from the acquisition date. The final allocation of the purchase price was as follows:

MUSTANG NET ASSETS ACQUIRED ($000s)	
Current assets	$ 10,523
Property and equipment	200,683
Goodwill	38,500
Current liabilities	(12,040)
Bank indebtedness	(26,188)
Asset retirement obligations	(5,019)
Future income tax liability	(45,259)
	$ 161,200
Value of units and exchangeable shares of the Trust issued	**$ 161,200**

The consideration for the Forte acquisition was 0.35 trust units for each Forte share resulting in 6.5 million trust units and 1.0 million exchangeable shares being issued. The value assigned to each trust unit was $7.60 based on the Thunder Energy share price at the time the Arrangement was announced. The value of the transaction was $113.5 million, net of the $35.1 million reduction for the conveyance of certain Forte assets and liabilities to Valiant prior to the amalgamation. The results of Forte have been included in the consolidated financial statements commencing from the acquisition date. The final allocation of the purchase price was as follows:

FORTE NET ASSETS ACQUIRED ($000s)	
Current assets	$ 13,577
Property and equipment	155,588
Goodwill	24,344
Current liabilities	(14,280)
Bank indebtedness	(23,540)
Asset retirement obligations	(7,596)
Future income tax liability	(34,590)
	$ 113,503
Value of units and exchangeable shares of the Trust issued	**$ 113,503**

In conjunction with the Plan of Arrangement, certain one-time external costs related to the reorganization of $8.7 million have been included as a capital cost and internal costs including $3.3 million in retention and severance have been charged to results of operations of the Trust. The costs related to the reorganization incurred by Mustang and Forte were reflected in the financial statements of those companies prior to the transaction date.

Under the Plan of Arrangement, Thunder Energy transferred certain assets and undeveloped land to Ember and Clipper. At the time of the transaction the companies were related, and consequently, the assets were transferred to Ember and Clipper at the Thunder Energy carrying values which, for the assets acquired by Thunder Energy from Forte and Mustang, were equal to fair market value. As part of the Arrangement, both Ember and Clipper paid $5.0 million to the Trust, which was accounted for as a reduction in capital for each entity.

The values transferred to Ember were as follows:

EMBER NET ASSETS TRANSFERRED ($000s)	
Property and equipment	$ 16,431
Future income tax asset	9,949
Asset retirement obligations	(1,487)
Total assets transferred	24,893
Cash paid	5,000
Net assets transferred and reduction in capital	**$ 19,893**

The values transferred to Clipper were as follows:

CLIPPER NET ASSETS TRANSFERRED ($000s)	
Property and equipment	$ 53,388
Future income tax asset	7,041
Accounts payable	(1,000)
Asset retirement obligations	(1,841)
Total assets transferred	57,588
Cash paid	5,000
Net assets transferred and reduction in capital	**$ 52,588**

In conjunction with the Plan of Arrangement, all outstanding stock options of Thunder Energy vested and option holders had the right to exercise their options until August 5, 2005 after which time the options expired. As a result, a stock-based compensation expense of $5.4 million was charged to the earnings of the Trust. Stock-based compensation of $0.6 million was apportioned to Ember ($0.2 million) and Clipper ($0.4 million) based on the relative reserve values of the proved and probable oil and natural gas reserves (discounted at 10%) as determined by independent reserve engineers.

3. PROPERTY AND EQUIPMENT

($000s)	Cost	Accumulated depletion and depreciation	Net book value
2006			
Petroleum and natural gas properties	**$ 674,128**	**$ 215,928**	**$ 458,200**
Gas plants and related facilities	**137,588**	**38,620**	**98,968**
Office equipment	**1,812**	**608**	**1,204**
	$ 813,528	**$ 255,156**	**$ 558,372**
2005			
Petroleum and natural gas properties	$ 709,222	$ 135,589	$ 573,633
Gas plants and related facilities	113,607	30,101	83,506
Office equipment	1,367	437	930
	$ 824,196	$ 166,127	$ 658,069

At December 31, 2006 costs of $24.8 million (2005 – $16.3 million) related to unproven properties were excluded from the full cost pool.

In 2006, the Trust capitalized $3.9 million (2005 – $1.6 million) of overhead directly related to acquisition, exploration and development activities.

The carrying value of the Trust's petroleum and natural gas properties and gas plant and related facilities is limited to the amount calculated under the ceiling test at the balance sheet date. At December 31, 2006, the calculation indicated the carrying value of the Trust's petroleum and natural gas properties and equipment was in excess of the amount calculated under the ceiling test. Accordingly, a write-down in the amount of $102.0 million (2005 – $56.2 million) was recorded. This write-down is primarily the result of downward revisions in the Trust's petroleum and natural gas reserves, as estimated by independent engineers as at December 31, 2006. The ceiling test calculation was based on benchmark reference prices adjusted for the Trust's quality and price differentials discounted at an interest rate of 6.4% (2005 – 6.8%) over the estimated reserve life.

The following table summarizes the benchmark reference prices used in the ceiling test calculation:

Year	WTI Oil ($US/bbl)	Edmonton Light Crude Oil 40° API ($Cdn/bbl)	NYMEX Gas Price ($US/mmbtu)	AECO Natural Gas Price ($Cdn/mmbtu)
2007	62.00	70.25	7.25	7.20
2008	60.00	68.00	7.50	7.45
2009	58.00	65.75	7.50	7.75
2010	57.00	64.50	7.50	7.80
2011	57.00	64.50	7.50	7.85
Escalate thereafter	2.0% per year	2.0% per year	2.0% per year	2.0% per year

4. GOODWILL

The Trust assessed goodwill for impairment at December 31, 2006 and determined that the fair value of the reporting unit had declined due to the write-down of oil and gas assets, as described in Note 3, and thus recorded a write-down of $58.6 million (2005 – nil). The following table reconciles the goodwill balance:

	($000s)
Balance December 31, 2004	$ 45,448
Goodwill on Plan of Arrangement (Note 2)	62,844
Balance December 31, 2005	108,292
Write-down of goodwill	(58,590)
Balance December 31, 2006	**$ 49,702**

5. 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 rate was 5.3% (2005 – 4.4%). Cash interest paid in the year was $5.7 million (2005 – $4.7 million).

6. 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 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, which are being amortized over the term of the Debentures, or as part of the equity component. A reconciliation of deferred financing costs is included in Note 7. 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 ($000s) (As at December 31)	**2006**
Debt component on April 5, 2006	**$ 73,298**
Accretion of non-cash interest in the period	**209**
Debt portion, December 31	**73,507**
Equity component	**1,702**
Total debentures, December 31	**$ 75,209**

Cash interest paid in the year was $3.1 million (2005 – nil).

7. FINANCIAL CHARGES

During the years ended December 31, 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:

FINANCIAL CHARGES ($000s)	**2006**	2005
Bank debt interest	**$ 5,640**	$ 5,357
Convertible debenture interest	**4,037**	–
Amortization of deferred financing costs	**539**	–
Accretion of convertible debenture liability	**209**	–
Total financial charges	**$ 10,425**	$ 5,357

A reconciliation of deferred financing costs is provided as follows:

DEFERRED FINANCING COSTS ($000s)	**2006**
Balance, beginning of period	**$ –**
Deferred financing costs	**3,426**
Amortization of deferred financing costs	**(539)**
Balance, December 31	**$ 2,887**

8. 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 $54.9 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 8.0% (2005 – 9%) and an inflation rate of 2.0% (2005 – 1.5%) were used to calculate the fair value of the asset retirement obligations. The Trust periodically reviews the assumptions used in its asset retirement obligations calculation. During the year, revisions were made to reflect changes in the inflation rate and the credit-adjusted risk-free rate.

A reconciliation of the asset retirement obligations is provided below:

ASSET RETIREMENT OBLIGATIONS ($000s)	**2006**	2005
Balance, beginning of year	**$ 24,774**	$ 13,417
Liabilities incurred in the year	**800**	1,758
Forte acquisition	**–**	7,596
Mustang acquisition	**–**	5,019
Revisions	**3,571**	(135)
Liabilities released to Ember and Clipper	**–**	(3,328)
Liabilities settled in the year	**(2,952)**	(1,306)
Accretion expense	**2,578**	1,753
Balance, end of year	**$ 28,771**	$ 24,774

9. UNITHOLDERS' CAPITAL

TRUST UNITS OF THUNDER ENERGY TRUST (including the conversion of exchangeable shares)	Number of units (000s)	($000s)
Trust units outstanding (see (a) below)	50,295	$ 442,948
Trust units issuable on conversion of exchangeable shares (see (b) below)	370	3,704
Balance December 31, 2006	**50,665**	**$ 446,652**

(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	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 2)	6,475	99,288
Issued on Mustang acquisition (Note 2)	9,607	123,810
Reduction of capital, Ember conveyance (Note 2)	–	(19,893)
Reduction of capital, Clipper conveyance (Note 2)	–	(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
Exchangeable shares converted	2,000	21,677
Unit issue costs, net of tax of $12	–	(50)
Distribution reinvestment program	4,224	34,060
Issued on exercise of restricted trust units	104	1,301
Balance December 31, 2006	**50,295**	**$ 442,948**

Premium Distribution Reinvestment and Optional Trust Unit Purchase Plan ("Premium DRIP™")

The Trust has a Premium Distribution Reinvestment and Optional Trust Unit Purchase Plan ("Premium DRIP™") for eligible unitholders of the Trust. On distribution payment dates eligible Premium DRIP™ unitholders may receive in lieu of the cash distribution that unitholders are otherwise entitled to receive in respect of their units, a cash payment equal to 102% of such amount. Unitholders may also reinvest their cash distribution in additional trust units at a price that is 95% of the Average Market Price for the Pricing Period. The Pricing Period refers to the period beginning on the later of the 21st business day preceding the distribution payment date and the second business day following the record date applicable to that distribution payment date, and ending on the second business day preceding the distribution payment date. The Average Market Price in respect of a particular Distribution payment date refers to the arithmetic average of the daily volume weighted average trading price of units traded during the corresponding Pricing Period. Eligible Premium DRIP™ unitholders may also make optional cash payments on this date to purchase additional trust units at a price that is equal to the average market price for the Pricing Period.

Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP")

The Trust has a Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") for eligible unitholders of the Trust. On distribution payment dates eligible DRIP unitholders may reinvest their cash distributions in additional trust units at a price that is 95% of the Average Market Price for the corresponding Pricing Period. Eligible DRIP unitholders may also make optional cash payments on this date to purchase additional trust units at a price that is equal to the 10-day weighted average trading price of trust units.

During the year, the Trust issued 4.2 million (2005 – 175,000) trust units from treasury for the DRIP which resulted in an increase to unitholders' capital of $34.1 million (2005 – $2.1 million).

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum of $50,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice of redemption. The redemption amount per trust unit will be the lesser of 90% of the market price of the trust units on the principal market on which they are quoted for trading during the 10-day trading period immediately prior to the date on which the trust units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the highest and lowest prices of the trust units of the date.

(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	1,759	13,030
Issued on Forte acquisition	927	14,215
Issued on Mustang acquisition	997	12,849
Exchanged for trust units	(1,495)	(14,713)
Balance December 31, 2005	2,188	$ 25,381
Exchanged for trust units	(1,818)	(21,677)
Balance December 31, 2006	**370**	**$ 3,704**

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 Exchange Ratio is calculated by multiplying the Thunder Energy Trust distribution per unit by the Exchange Ratio immediately prior to 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 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 December 15, 2006, the Exchange Ratio was 1.26071. If the 0.4 million exchangeable shares outstanding at December 31, 2006 were exchanged at that time, 0.5 million trust units would have been issued.

(c) Contributed Surplus

The following table reconciles the Trust's contributed surplus:

		($000s)
Balance December 31, 2004	$	2,836
Stock-based compensation		7,287
Options exercised for trust units		(7,098)
Balance December 31, 2006 and 2005	**$**	**3,025**

(d) Trust Unit Incentive Plans

The Trust approved a restricted unit incentive plan and a performance unit incentive plan (the "Plans"). Under the terms of the Plans, both restricted and performance units ("RTUs" and "PTUs") may be granted to directors, officers, employees, consultants and service providers (the "Plan Participants") to the Trust and any of its subsidiaries.

Subject to the Board of Directors of the Trust's administrator, Thunder Energy, determining otherwise, (i) RTUs of the Trust vest evenly over three years, commencing on the first anniversary date of grant, with the number of trust units issued adjusted for the value of the distributions from the time of the granting to the time when the trust units are issued, and (ii) PTUs vest on the third anniversary date of the grant, adjusted for the value of the distributions, plus a further upward or downward adjustment based on the Trust's performance relative to the performance of a group of comparable publicly-traded oil and gas royalty trusts. Upon vesting and at management's option, the Plan Participant is entitled to receive either the units granted plus accumulated distributions or the cash payment based on the fair value of the underlying trust units plus notional accrued distributions. As such, the fair value associated with the RTUs and PTUs is expensed in the statement of loss over the vesting period. As the value of the RTUs and PTUs is dependent upon the trust unit price, the expense recorded in the consolidated statement of loss may vary from period to period.

The Trust recorded a compensation expense of $1.7 million for the year (2005 – $8.6 million) resulting in a current liability of $0.6 million and a long-term liability of $1.0 million. The decrease from prior year relates to the vesting of stock options on the formation of the Trust as described in Note 2. The compensation expense was based on the December 31, 2006 unit closing price of $5.67 per unit, distributions of $0.15 per unit from January to April and $0.12 per unit from May to December as well as management's estimate of the number of RTUs and PTUs to be issued on maturity. No estimate has been made for forfeitures as the Trust accounts for actual forfeitures as they occur. The following table summarizes the RTU and PTU movement for the year ended December 31, 2006.

RESTRICTED AND PERFORMANCE TRUST UNITS (000s)	RTUs	PTUs
Balance December 31, 2004	–	–
Granted	283	59
Exercisable	–	–
Balance December 31, 2005	283	59
Granted	242	107
Cancelled	(43)	(13)
Redeemed	(104)	–
Balance December 31, 2006	**378**	**153**

(e) Per Unit Amounts

The following table summarizes the weighted average basic and diluted trust units and exchangeable shares used in calculating net loss per trust unit:

TRUST UNITS (000s)	**2006**	2005
Weighted average trust units	**47,279**	41,373
Exchangeable shares at exchange ratio	**739**	3,360
Trust units (basic)	**48,018**	44,733
Convertible debentures	–	–
Restricted and performance trust units	–	205
Trust units (diluted)	**48,018**	44,938

The units issuable under the trust unit incentive plan and the convertible debentures have been excluded since they would be anti-dilutive and thus have not been included in the diluted per unit calculations for the year ended December 31, 2006.

10. ACCUMULATED DISTRIBUTIONS

The table below shows the cumulative distributions for the Trust:

ACCUMULATED DISTRIBUTIONS ($000s)	Cash distributions	DRIP	Total
July distribution	$ 6,301	$ –	$ 6,301
August distribution	6,394	–	6,394
September distribution	6,419	–	6,419
October distribution	6,515	–	6,515
November distribution	4,450	2,072	6,522
December distribution	4,283	2,312	6,595
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
April distribution	3,543	3,428	6,971
May distribution	2,907	2,722	5,629
June distribution	2,987	2,716	5,703
July distribution	3,029	2,731	5,760
August distribution	3,004	2,795	5,799
September distribution	3,075	2,765	5,840
October distribution	2,784	3,120	5,904
November distribution	2,797	3,168	5,965
December distribution	2,992	3,043	6,035
2006 distributions	39,300	34,791	74,091
Balance, December 31, 2006	**$ 73,662**	**$ 39,175**	**$ 112,837**

11. INCOME TAXES

The Trust is a taxable entity under the *Tax Act* 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 loss and accumulated earnings (deficit) differ from the tax calculated by applying the combined Canadian corporate federal and provincial income tax rate to income before taxes as follows:

INCOME TAXES ($000s, except where noted)	2006	2005
Statutory income tax rate for year	**35.03%**	37.75%
Computed income tax recovery	**$ (59,821)**	$ (10,559)
Add (deduct) income tax effect of:		
Non deductible Crown charges, net of ARTC	**(175)**	4,447
Resource allowance	**-**	(5,217)
Unit-based compensation	**581**	3,240
Taxable distributions	**(23,073)**	(11,823)
Write-down of goodwill (Note 4)	**20,524**	–
Tax rate adjustments	**(9,612)**	258
Other	**27**	13
Future income tax	**(71,549)**	(19,641)
Current taxes	**244**	1,521
Provision for income taxes (recovery)	**$ (71,305)**	$ (18,120)

Cash taxes paid were for Saskatchewan capital tax in the year ended December 31, 2006 and Federal large corporations tax and Saskatchewan capital tax for the year ended December 31, 2005.

The primary components of the future income tax liability relate to the following:

FUTURE INCOME TAX LIABILITY ($000s)	2006	2005
Property and equipment	**$. 91,974**	$ 143,652
Deferral of partnership income	**19,913**	32,608
Commodity contracts	**1,395**	–
Tax loss carry forwards recognized	**(23,215)**	(17,779)
Attributed Canadian royalty income	**(4,850)**	(1,567)
Asset retirement obligations	**(8,807)**	(8,329)
Unit issue costs	**(1,125)**	(1,709)
Deferred financing costs	**30**	–
Future income tax liability	**75,315**	146,876
Less current future income tax liability	**1,395**	–
Long-term future income tax liability	**$ 73,920**	$ 146,876

The Trust's tax pools totaled $337 million at December 31, 2006 (2005 – $288 million).

On October 31, 2006, the Federal Minister of Finance announced proposals (the "October 31, 2006 Proposals") to amend the *Tax Act* to apply a tax on distributions from publicly-traded income trusts. Under the October 31, 2006 Proposals, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, or sooner under certain circumstances following a four-year grace period. The Federal Minister of Finance has issued a Notice of Ways and Means Motion to Amend the *Tax Act*, but it is not known at this time if or when the proposal will be enacted by Parliament. The Trust is currently assessing the proposals and the potential implications to the Trust.

12. 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	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
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$61.00 to US$73.05	Jan 1/07 to March 31/07
Costless collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to March 31/07
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

The net effect of these contracts was a realized net gain of $0.7 million and an unrealized net gain of $4.6 million for the year ended December 31, 2006 (2005 – nil).

Subsequent to December 31, 2006, the Trust entered into the following financial transaction to mitigate its exposure to future fluctuations in commodity prices.

Gas Contract	Volume (gj/d)	Pricing Point	Strike Price (per gj)	Term
Costless collar	8,000	AECO	Cdn$6.50 to Cdn$8.00	April 1/07 to Oct 31/07

13. SUPPLEMENTAL CASH FLOW INFORMATION

SUPPLEMENTAL CASH FLOW INFORMATION ($000s)	**2006**	2005
Changes in non-cash working capital:		
Accounts receivable	**$ 14,340**	$ (26,082)
Prepaid expenses	**(2,162)**	(266)
Accounts payable and accrued liabilities	**(19,305)**	9,961
Assumption of working capital on acquisitions (Note 2)	**–**	(2,220)
	$ (7,127)	$ (18,607)
Changes in non-cash working capital		
Operating activities	**$ (557)**	$ (27,619)
Investing activities	**(6,570)**	9,012
	$ (7,127)	$ (18,607)

14. RISK MANAGEMENT

a) Credit Risk

A substantial portion of the Trust's accounts receivable are with oil and gas marketing entities. The Trust generally extends unsecured credit to these companies; therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which it extends credit.

The Trust is exposed to losses in the event of non-performance by counterparties to financial risk management contracts. The Trust minimizes credit risk associated with possible non-performance of these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. The Trust believes these risks are minimal.

The Trust has not previously experienced any material credit losses on the collection of receivables.

b) Fair Value of Financial Instruments

Financial instruments of the Trust consist of accounts receivable, commodity contracts, bank indebtedness, accounts payable, distributions payable, unit-based compensation, bank debt, convertible debentures and asset retirement obligations. The carrying amounts of financial instruments included in the balance sheet approximate their fair value.

c) Interest Rate Risk Management

Borrowings under bank credit facilities are market-rate-based (variable interest rates); thus exposing the Trust to interest rate risk.

d) Foreign Currency Risk Management

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in US dollars, while the majority of the Trust's expenses are denominated in Canadian dollars.

15. RELATED PARTY TRANSACTIONS

During the year, the Trust incurred expenditures of $0.5 million (2005 – $1.0 million) for general corporate legal fees charged by 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 December 31, 2006, $1,750 (2005 – $10,000) remained outstanding. The related party transactions were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.

16. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND GUARANTEES

The Trust has assumed various contractual obligations and commitments in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing cash requirements in the analysis of future liquidity.

($000s)	Total	< 1 year	Payments 1-3 years	4-5 years	> 5 years
Firm transportation	**$ 1,243**	$ 500	$ 743	$ –	$ –
Power contract	**1,221**	1,051	170	–	–
Office and vehicle leases	**12,205**	2,022	6,326	3,857	–
Total	**$ 14,669**	$ 3,573	$ 7,239	$ 3,857	$ –

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers.

CORPORATE INFORMATION

DIRECTORS

Douglas A. Dafoe, CA (2) (4) (5)
Chairman of the Board, Chief Executive Officer and Executive Chairman
Ember Resources Inc.

Colin D. Boyer, P. Eng (1) (3)
Independent Businessman

John Clark (1) (5)
President,
Investments and Technical Management Corp.

Stuart J. Keck, P. Eng (4)
President and Chief Executive Officer,
Thunder Energy Trust

Thomas J. MacKay (3) (4)
Independent Businessman

Patrick Mills (1) (3)
President and Chief Executive Officer,
Pegasus Oil & Gas Inc.

James M. Pasieka (2)
Barrister & Solicitor,
Heenan Blaikie LLP

Richard A. M. Todd (2) (5)
Executive Chairman and Chief Executive Officer,
Oil Sands Underground Mining Corp.

(1) Audit Committee
(2) Compensation Committee
(3) Reserve Evaluation Committee
(4) Health, Safety and Environment Committee
(5) Hedging Committee

OFFICERS

Stuart J. Keck, P. Eng
President and Chief Executive Officer

Pamela Kazeil, CA*
Vice President, Finance
and Chief Financial Officer

Steven R. Gell, P. Eng
Vice President, Production

G.L. (Gerry) Boyer, P. Eng
Vice President, Engineering

Brad Crowe
Vice President, Land

Tony Cadrin, Ph.D, P. Geol
Vice President, Geosciences

* Brent T. Kirkby resigned as Vice President, Finance and Chief Financial Officer on March 15, 2007

NOTICE OF MEETING

The Annual General meeting will be held on Tuesday, May 22, 2007 at the Metropolitan Centre, Strand Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta beginning at 3:00 p.m. MDT.

Unitholders are encouraged to attend. Those unable to attend are asked to complete and return their Form of Proxy.

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Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

LEGAL COUNSEL

Heenan Blaikie LLP
Calgary, Alberta

BANKERS

Bank of Montreal
CIBC
ATB Financial
Société Générale
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Olympia Trust Company
Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange
Symbol: THY.UN
THY.DB

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrels of oil or natural gas liquids
bcf	billion cubic feet of natural gas
boe	barrels of oil equivalent (6,000 cubic feet of natural gas is equivalent to one barrel of oil)
/d	per day
gj	gigajoule
mbbl	thousand barrels
mmbbl	million barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet of natural gas
mmcf	million cubic feet of natural gas
mmbtu	million British thermal units
NGL	natural gas liquids
Premium Distribution™	Canaccord Capital Corporation

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END

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