TRUE energy trust

For Immediate Release
TSX: TUI.UN

TRUE ENERGY TRUST ANNOUNCES YEAR END 2007 FINANCIAL RESULTS

March 6, 2008 – (TSX: TUI.UN) True Energy Trust ("True" or the "Trust") announces its financial and operating results for the year ended December 31, 2007. Highlights from the fourth quarter and year ended December 31, 2007 include:

- In the fourth quarter of 2007, monthly distributions of $0.08 per unit were declared and paid on November 15, 2007, December 17, 2007 and January 15, 2008 resulting in annual cash distributions paid of $0.96 per unit. The Board has announced it has set a distribution policy for the first quarter of 2008 at a monthly rate of $0.04 per unit, subject to monthly confirmation, based on current commodity prices, hedging program, production volumes and market conditions. True anticipates that this reduction will allow the Trust's distributions to be sustainable in the current gas price, foreign exchange rate and cost environment.
- True generated average sales volumes for the year of 16,139 boe/d as compared to 13,861 boe/d in 2006, representing a 16% increase. Average sales volumes for the fourth quarter of 2007 were 14,937 boe/d as compared to 19,747 boe/d for the same period in 2006, representing a 24% decrease. This decrease in average sales volumes from fourth quarter 2006 to 2007 was due to natural production declines, decreased production due to property dispositions during 2007, the delay of tie-in and completion of certain third party first quarter drilled wells until late in 2007, and the impact of slowly increasing production for the capital intensive Kerrobert SAGD expansion project, which will continue to advance into 2008. Sales volumes in the fourth quarter were up 6% from the third quarter 2007 volumes. The increase in sales volumes from the third to fourth quarter of 2007 takes into account the resumption of certain production following plant turnarounds and other operational challenges in the third quarter.
- Funds flow from operations * for 2007 was $101.2 million on gross sales of $258.5 million compared to funds flow from operations of $90.4 million on gross sales of $220.9 million for 2006. The increase in funds flow for the 2007 year was primarily the result of higher sales volumes, offset by marginally lower overall commodity prices and operating netbacks for 2007. Funds flow from operations for the fourth quarter was $19.5 million on gross sales of $61.8 million compared to funds flow from operations of $31.8 million on gross sales of $77.2 million for the same period in 2006. This is primarily reflective of reduced sales volumes in fourth quarter 2007 compared to the same period in 2006, offset by an overall increase in commodity prices between those periods.
- The net loss for 2007 was $24.3 million compared to a net loss of $233.6 million for 2006. The net loss for the 2007 fourth quarter was $0.4 million compared to a net loss of $250.7 million in the same period in 2006. The 2006 year included fourth quarter non-cash charges for the ceiling test write-down of property, plant and equipment of $110.0 million and goodwill impairment of $169.8 million.
- During 2007, True achieved a 98% success rate in drilling or participation in 40 (27.3 net) working interest wells, resulting in 20 (10.4 net) gas wells, 17 (14.4 net) oil wells, 2 (2.0 net) stratagraphic test wells and 1 (0.5 net) dry hole.
- On December 17, 2007 the Trust announced its intention to divest of its Saskatchewan assets as part of a new strategic direction. Bids were received on March 4, 2008 and are presently being evaluated by the Trust with the assistance of its financial advisor, Scotia Waterous Inc.
- After giving recognition to property sales, True replaced approximately 99% of its production with 2007 year end working interest gross proved plus probable reserves of 45.4 mmboe.
- The Trust recorded all-in annual Finding, Development and Acquisition ("FD&A") cost of $21.60 per barrel of oil equivalent ("boe") in 2007 before consideration of future development capital ("FDC") for proved plus probable reserves category. This is a 12 percent reduction from the $24.60 per boe FD&A cost realized in 2006. Including FDC, the FD&A cost was $21.10 per boe. The three year average FD&A cost is $26.30 per boe for the proved plus probable category before FDC; including FDC, the three year average FD&A cost is $28.60 per boe. For additional information please refer to the reserves news release dated March 6, 2008 (posted on www.sedar.com).

* Refer to note (2) in the highlights section of the financial report in respect of the term "funds flow from operations", which is also commonly referred to as "cash flow from operations".

True's 2007 financial report is presented below.

HIGHLIGHTS

		Years ended December 31 2007	2006
FINANCIAL			
(CDN $000s except unit and per unit amounts)			
Revenue (before royalties and hedging[1])		258,490	220,913
Funds flow from operations [2]		101,172	90,391
Per basic trust unit		$1.33	$1.91
Per diluted trust unit		$1.33	$1.87
Net loss		(24,267)	(233,564)
Per basic trust unit		$(0.32)	$(4.95)
Per diluted trust unit		$(0.32)	$(4.95)
Distributions paid		73,451	124,355
Per unit		$0.96	$2.64
Exploration and development		87,397	98,690
Corporate and property acquisitions		1,505	17,322
Capital expenditures - cash		88,902	116,012
Property dispositions - cash		(31,808)	(24,514)
Corporate acquisitions and other - non-cash		270	487,698
Total capital expenditures - net		57,364	579,196
Long-term debt		168,475	157,904
Convertible debentures [3]		79,407	81,551
Working capital deficiency [3]		3,281	36,361
Total net debt [3]		251,163	275,816
Total assets		880,252	1,016,658
Unitholders' equity		462,780	505,096
OPERATING			
Daily sales volumes			
Crude oil and NGLs	(bbls/d)	5,330	5,317
Natural gas	(mcf/d)	64,853	51,264
Total oil equivalent	(boe/d)	16,139	13,861
Average prices			
Crude oil and NGLs	($/bbl)	48.71	48.00
Crude oil and NGLs (including hedging[1])	($/bbl)	41.88	47.54
Natural gas	($/mcf)	6.73	6.75
Natural gas (including hedging[1])	($/mcf)	7.13	6.93
Total oil equivalent	($/boe)	43.13	43.36
Total oil equivalent (including hedging[1])	($/boe)	42.47	43.88
Statistics			
Operating netback [4]	($/boe)	22.21	22.60
Operating netback (including hedging[1]) [4]	($/boe)	21.55	23.12
Production expenses	($/boe)	11.59	9.23
General & administrative	($/boe)	3.09	2.94
Royalties as a % of sales after transportation		19%	24%

	Years ended December 31	
	2007	**2006**
TRUST UNITS		
Trust units outstanding	79,216,046	70,275,703
Trust unit incentive rights outstanding	5,931,997	5,429,831
Units issuable for exchangeable shares	335,793	286,942
Units issuable for convertible debentures	5,390,625	5,390,625
Diluted trust units outstanding	90,874,461	81,383,101
Diluted weighted average trust units [5]	75,792,488	47,217,258

TRUST UNIT TRADING STATISTICS		
(CDN$, except volumes) based on intra-day trading		
High	7.47	21.30
Low	2.76	7.25
Close	3.35	7.49
Average daily volume	492,004	412,447

[1] *The Trust has entered into various commodity risk management contracts which are considered to be economic hedges. As disclosed in note 3 of the financial statements, effective January 1, 2007, the Trust no longer applies hedge accounting to these contracts. As such, these contracts are revalued to fair value at the end of each reporting date. This results in recognition of unrealized gains or losses over the term of these contracts which is reflected each reporting period until these contracts are settled, at which time realized gains or losses are recorded.*

[2] *The highlights section contains the term "funds flow from operations" (or as commonly referred to as "cash flow from operations"), which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Trust's performance. Therefore reference to diluted funds flow from operations or funds flow from operations per trust unit may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between funds flow from operations and cash flow from operating activities can be found in the Management Discussion and Analysis ("MD&A"). Funds flow from operations per trust unit is calculated using the weighted average number of trust units for the period.*

[3] *Net debt includes the net working capital deficiency before short-term commodity contract assets and liabilities and short-term future income tax assets. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.*

[4] *Operating netbacks are calculated by subtracting transportation, royalties and operating costs from revenues.*

[5] *In computing weighted average diluted earnings per trust unit for the year ended December 31, 2007 a total of 335,793 (2006: 286,942) exchangeable shares, 5,931,997 (2006: 5,429,831) trust incentive units and 5,390,625 (2006: 5,390,625) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the year ended December 31, 2007 and 2006 as they were not dilutive. To calculate weighted average diluted funds flow from operations for the year ended December 31, 2007, 335,793 exchangeable shares were added to the denominator, resulting in diluted weighted average trust units of 76,128,281 under this calculation. To calculate weighted average diluted funds flow from operations for the year ended December 31, 2006, a total of $4.0 million for interest accretion expense was added to the numerator and 286,942 exchangeable shares and 2,953,757 trust units were added to the denominator for units issuable on conversion of convertible debentures, resulting in diluted weighted average trust units of 50,457,967 and funds flow from operations per diluted trust unit of $1.87 under this calculation.*

REPORT TO UNITHOLDERS

Natural gas prices continue to be highly volatile, largely due to uncertainty regarding weather and its effect on natural gas demand and storage and global factors including LNG shipments to North America. True continues to be cautious in its outlook with respect to near term natural gas prices and is actively managing its forward gas price exposure to mitigate risks.

Accomplishments for the fourth quarter and year ended December 31, 2007 include:

Distributions
In the fourth quarter of 2007, monthly distributions of $0.08 per unit were declared and paid on November 15, 2007, December 17, 2007 and January 15, 2008 resulting in annual cash distributions paid of $0.96 per unit.

On December 17, 2007, the Trust announced that the Board has set the distribution policy for the first quarter of 2008 at a monthly distribution rate of $0.04 per unit, subject to monthly confirmation by the Board of Directors, based on current commodity prices, hedging program, anticipated production volumes and market conditions. True anticipates that this reduction will allow the Trust's distributions to be sustainable in the current gas price, foreign exchange rate and cost environment.

Production
For the 2007 year, sales volumes averaged 16,139 boe/d as compared to 13,861 boe/d for the same period in 2006. This reflects the full integration of additional production from the closing of the acquisitions of Shellbridge Oil & Gas, Inc. on June 23, 2006 and Prairie Schooner Petroleum Ltd. on September 22, 2006, in addition to the impact from drilling and operational activity in 2007.

2007 fourth quarter sales volumes averaged 14,937 boe/d as compared to 19,747 boe/d for the same period in 2006, representing a 24% decrease. This decrease in average sales volumes from fourth quarter 2006 to 2007 was due to natural production declines, decreased production due to property dispositions during 2007, the delay of tie-in and completion of certain third party first quarter drilled wells until late in 2007, and the impact of slowly increasing production for the capital intensive Kerrobert SAGD expansion project, which will continue to advance into 2008. Sales volumes in the fourth quarter were up 6% from the third quarter 2007 volumes. The increase in sales volumes from the third to fourth quarter takes into account the resumption of certain production following plant turnarounds and other operational challenges in the third quarter. However, production for fourth quarter 2007 was lower than anticipated due to somewhat slower than anticipated SAGD response at Kerrobert.

Field production estimates for the first quarter of 2008 are expected to average approximately 13,200 boe/d. Field production was adversely impacted by the extreme weather experienced in January and February of 2008. In addition, an unplanned third party plant outage impacted production in west central Alberta for February 2008. Work is underway to deal with a well servicing and equipment repair backlog.

Drilling
During the 2007 year, True achieved a 98% success rate in drilling or participation in 40 (27.3 net) working interest wells, resulting in 20 (10.4 net) gas wells, 17 (14.4 net) oil wells, 2 (2.0 net) stratagraphic test wells and 1 (0.5 net) dry hole.

Only 6 (3.3 net) wells were drilled subsequent to the first quarter 2007 including 3 (1.0 net) third party operated wells in the fourth quarter of 2007. The Trust currently plans to drill 2 (2.0 net) operated exploration wells late in the first quarter of 2008.

Kerrobert
Advancement of the Kerrobert SAGD project continues. During the first quarter of 2008, True has increased steam rates to the 4 new steam injectors to near maximum levels. Wellhead injection pressures have uniformly increased indicating a re-pressurization of the reservoir. Further evidence of re-pressurization has been seen through the consistent increase of wellbore fluid levels and downhole pump inlet pressures. Production well temperatures have remained at near initial reservoir levels indicating even heating is underway and that no random, premature, breakthrough has occurred – a positive indicator of overall project conformance. Based on the recovery responses of the original 1996 pilot project, estimated oil rate increases on the current project should occur 4 to 6 months after start-up. As we approach the midpoint of the 4 to 6 month timing range it is clear there will not be an "early" response, however all technical parameters continue to point to a very positive project.

Financial
Funds flow from operations for the 2007 year was $101.2 million on gross sales of $258.5 million compared to funds flow from operations of $90.4 million on gross sales of $220.9 million for 2006. The increase in funds flow for the 2007 year was primarily the result of higher sales volumes, offset by marginally lower overall commodity prices and operating netbacks for 2007.

Funds flow from operations for the fourth quarter was $19.5 million on gross sales of $61.8 million compared to funds flow from operations of $31.8 million on gross sales of $77.2 million for the same period in 2006. This is primarily reflective of reduced sales volumes in fourth quarter 2007 compared to the same period in 2006, offset by an overall increase in commodity prices between those periods.

The net loss for the 2007 year was $24.3 million compared to a net loss of $233.6 million for 2006. The net loss for the 2007 fourth quarter was $0.4 million compared to a net loss of $250.7 million in the same period in 2006. The 2006 year included fourth quarter non-cash charges for the ceiling test write-down of property, plant and equipment of $110.0 million and goodwill impairment of $169.8 million.

Dispositions
During 2007, True identified certain small non-core property disposition opportunities, which were in keeping with its principles of core areas for future development and operating high working interest production. For the 2007 year, True closed on various property dispositions for total net proceeds after adjustments of $31.8 million. The proceeds from all property dispositions were used to pay down bank debt. In the fourth quarter of 2007, True closed on a minor Alberta property disposition for total net proceeds of $0.5 million.

Liquidity
True's net debt, excluding unrealized commodity contract assets and liabilities, future income taxes and ARO, as at December 31, 2007 was $251.2 million, representing $168.5 million outstanding on the credit facility, $79.4 million in convertible debentures (liability component) and the balance a working capital deficiency.

On May 31, 2007, the Trust completed its offering, including an over-allotment option, for an aggregate of 9,430,000 trust units for gross proceeds of $57.5 million. The net proceeds of $54.4 million, after deducting unit issue costs, was used to pay down debt.

The existing credit facility consists of a $15 million demand operating facility provided by one Canadian bank and a $175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution and one institutional lender. As at December 31, 2007, there is approximately $22 million not drawn under these lending facilities.

True does not hold any non-bank Asset-Backed Commercial Paper investments.

The revolving period on the term credit facility ends on June 30, 2008, unless extended for a further 364 day period. The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on March 31, 2008.

In August 2007, True received Toronto Stock Exchange approval for its normal course issuer bid ("NCIB") for the repurchase of its trust units from August 28, 2007 to August 27, 2008, entitling the Trust to purchase up to approximately 7.8 million of its outstanding trust units. Starting in the fourth quarter and through the end of 2007, 500,000 units were repurchased at a total price of $1.7 million. Future repurchases will be dependent on excess cash available after consideration of the Trust's priority uses of cash and the trading price of the Trust's units.

True has continued its active commodity price risk management program. Further to our press release dated February 19, 2008, True has recently entered into seven additional fixed natural gas management contracts. With the addition of these contracts, approximately 33% of current natural gas production is hedged through the first quarter of 2008. Assuming the previously announced sale of the Trust's Saskatchewan assets is completed at the end of Q1 2008, approximately 53% of estimated natural gas production is hedged through the balance of 2008 and approximately 23% is hedged through the first half of 2009. The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's unitholder distributions and the capital program.

International Opportunity
The formal signing of the License Contract (the "Agreement") for the exploration and exploitation of hydrocarbons in Block 126, Peru (the "Block") occurred on October 23, 2007 in Lima, Peru. The ceremony included the Minister of Energy and Mines of Peru, senior members of Petroperu and roughly 150 invited guests. A wholly owned subsidiary of True is the operator of the project in a partnership with Veraz Petroleum Ltd. (the "Partnership"). Veraz Petroleum Ltd. ("Veraz") is a junior international oil and gas exploration company based in western Canada and listed on the Canadian Trading and Quotation System Inc. (CNQ).

The Agreement provides the exclusive right to the Partnership to explore for and develop hydrocarbons on the 2.5 million acre Block located in Ucayali province, east central Peru and entitles True to a 10% working interest and Veraz to a 90% working interest subject to standard royalties payable to the Government of Peru. The Partnership intends to begin exploration and development activities as soon as possible. To date, previous partnership groups have drilled only three wells on the Block. The focus of any preliminary work will be on the previous exploration work completed on the Block in the 1980's, which confirmed the presence of hydrocarbons.

Pursuant to the Agreement, the Partnership has been issued a seven year, four phase exploration permit to be followed by an exploitation phase in the event of a commercial discovery. Each phase has commitments that the Partnership must meet before the next phase can be undertaken. At the end of each phase the operator elects whether or not the Partnership continues into the subsequent phase. In the first phase, the Partnership will reprocess approximately 1,000 km of existing 2D seismic data. Much of this data, which was primarily acquired in the mid to late 1980's, has not been re-evaluated using contemporary processing techniques.

The first exploration phase of the Agreement is for one year commencing December 21, 2007 and requires a minimum work period commitment by the Partnership of US$200,000 (True's 10% share is US$20,000). If the Partnership continues into the second phase, a further US$2.5 million minimum commitment by the Partnership (True's 10% share is US$250,000) would be required. If the Partnership continues with the third and fourth phases of the Agreement an additional US$1.25 million minimum commitment would be required by the Partnership for each additional phase. Should the Partnership proceed through all four exploration phases the minimum work commitment by the Partnership would total US$5.2 million (True's 10% share is US$520,000).

Regulatory Changes

On October 25, 2007, the Alberta Government announced its intent to increase royalty rates commencing on January 1, 2009. As of December 31, 2007, the province had not introduced the enabling legislation nor had they provided enough clarity on a number of issues for the Trust's independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to provide a precise calculation of the net reserves and NPV under the New Royalty Framework ("NRF"). However, GLJ did provide analysis of the proposed royalty regime, based on a high and low sensitivity to the NRF utilizing the Consultants' Consensus Methodology recommended by the Society of Petroleum Engineers, Calgary Chapter (the "Consensus Methodology"). Based on currently available public information, the net present value of future net revenue of proved and probable reserves based on the high scenario at a 10% discount rate using the Consultants' Average Forecast Prices would be $8.9 million or 1.5 percent higher and $1.9 million or 0.33% percent higher based on the NRF for the low scenario, in each case, as compared to the existing royalty rules. The proposed royalty changes are very sensitive to production rate and natural gas prices. The majority of True's current Alberta wells are in the 500m to 1,000m depth range and typically produce at lower rates. The overall impact of the new Alberta royalty regime, as currently announced, is mitigated by the Trust's current Saskatchewan properties and the lower shallow gas Alberta natural gas rate royalty production in True's Alberta conventional oil and gas production portfolio. The New Alberta Royalty Framework will impact future drilling decisions in order for the Trust to maintain acceptable rates of return on its capital deployed. The Alberta Government has stated that they are reviewing with industry the proposed royalty changes to ensure that there are no unintended consequences resulting from the royalty changes. It is not known at this time whether any further revisions to the proposals will be made nor what their impact may be.

On October 30, 2007, the Finance Minister announced, as part of the 2007 Economic Statement, changes to the tax system including reduction of the corporate income tax rate from 22.1 per cent to 15 per cent by 2012. The reductions will be phased in between 2008 and 2012. Legislation enacting the measures announced in the Economic Statement received Royal Assent on December 14, 2007. The reduction in the general corporate tax rate will also apply to the taxation of income trusts, reducing the combined federal and deemed provincial tax rate for distributions to 28 per cent in 2012.

Finding, Development and Acquisition Costs

After giving recognition to property sales, True replaced approximately 99% of its production with 2007 year end working interest gross proved plus probable reserves of 45.4 mmboe.

The Trust recorded all-in annual Finding, Development and Acquisition ("FD&A") cost of $21.60 per barrel of oil equivalent ("boe") in 2007 before consideration of future development capital ("FDC") for proved plus probable reserves category. This is a 12 percent reduction from the $24.60 per boe FD&A cost realized in 2006. Including FDC, the FD&A cost was $21.10 per boe. The three year average FD&A cost is $26.30 per boe for the proved plus probable category before FDC; including FDC, the three year average FD&A cost is $28.60 per boe. For additional information please refer to the reserves news release dated March 6, 2008 (posted on www.sedar.com).

Announcement of Saskatchewan Assets Divestiture Program

On December 17, 2007, True announced its intention to divest of its Saskatchewan assets as part of a new strategic direction for the Trust. Further to this announcement, True intends to divest its oil and natural gas assets in Saskatchewan including Kerrobert's SAGD project, and properties at Smiley, Coleville, Dodsland and Mantario.

December 2007 average production from the Saskatchewan assets was approximately 5,600 boe/d, weighted 62% to oil (97% heavy oil, 3% light oil). The assets include 18.8 mmboe of reserves and approximately 250,000 net acres of land. True anticipates significant proceeds from the disposition of its Saskatchewan properties in a time of historically high oil prices and the current favorable royalty regime in Saskatchewan. Any proceeds from the proposed divestiture will be utilized to eliminate True's bank indebtedness and to provide additional financial resources to develop its Alberta light oil and natural gas plays. Scotia Waterous Inc. ("Scotia Waterous") has been selected to act as True's exclusive advisor in this process. Bids were received on March 4, 2008 and are presently being evaluated by the Trust with the assistance of Scotia Waterous. Assuming True's acceptance of satisfactory bid(s), the asset divestiture is currently anticipated to close at the end of the first quarter of 2008.

2008 True Capex Budget

Gas prices continue to show volatility with uncertainty regarding weather and its effect on natural gas demand and storage and global factors including LNG shipments to North America. Given the natural gas price outlook, coming into the winter drilling season, True plans to reduce its first quarter 2008 winter drilling activity compared to the first quarter of 2007. True's first quarter 2008 capital program will not exceed $10 million which compares to a front end loaded 2007 capital program of approximately $50 million in first quarter 2007. True will continue to take a balanced approach to the priority use of cash flow between level of distributions and size of its 2008 capital program. After completion of the proposed asset divestiture, True's 2008 capital expenditure program would be increased from the currently planned $40 million to approximately $60 million. Given the nature of True's lands and their inherent advantage of year round access, True will spread its 2008 capital program more evenly through the full year of 2008 to take advantage of reduced service costs during non-peak times. True will focus on increasing its farm-out activity in non-core areas. If the 2008 outlook for commodity prices improves, True would plan to increase its capital spending in third and fourth quarters of 2008.

A conference call to discuss True's annual financial and reserves results will be held on March 6, 2008 at 2:00 PM MST/4:00 PM EST. To participate, please call toll-free 1-800-587-1893 or 416-644-3428. The conference call will also be recorded and available by calling 1-877-289-8525 or 416-640-1917 and entering passcode 21264766 followed by the pound sign.

True's annual meeting is scheduled for 2:00pm on May 21, 2008 in the Grand Lecture Theatre at the Metropolitan Conference Center in Calgary.

Wayne M. Chorney, P. Eng.
President, CEO and COO
March 6, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 6, 2008 - The following Management's Discussion and Analysis of financial results as provided by the management of True Energy Trust ("True" or the "Trust") should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2007 and 2006 for the Trust. This commentary is based on information available to, and is dated March 6, 2008. The financial data presented is in accordance with Canadian generally accepted accounting principles ("GAAP") in Canadian dollars, except where indicated otherwise.

CONVERSION: The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf/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 from converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

NON-GAAP MEASURES: This Management's Discussion and Analysis contains the term "funds flow from operations"(or also commonly referred to as "cash flow from operations"), which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's performance. Therefore reference to funds flow from operations or funds flow from operations per unit may not be comparable with the calculation of similar measures for other entities. Management uses funds flow from operations to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between funds flow from operations and cash flow from operating activities can be found in the Management's Discussion and Analysis. Funds flow from operations per unit is calculated using the weighted average number of units for the period.

This Management's Discussion and Analysis also contains other terms such as net debt and operating netbacks, which are not recognized measures under Canadian GAAP. Management believes these measures are useful supplemental measures of firstly, the total amount of current and long-term debt and secondly, the amount of revenues received after transportation, royalties and operating costs. Readers are cautioned, however, that these measures should not be construed as an alternative to other terms such as current and long-term debt or net income determined in accordance with GAAP as measures of performance. True's method of calculating these measures may differ from other entities, and accordingly, may not be comparable to measures used by other trusts or companies.

Additional information relating to the Trust, including the Trust's Annual Information Form, is available on SEDAR at www.sedar.com.

FORWARD LOOKING STATEMENTS: Certain information contained herein may contain forward looking statements including management's assessment of future plans and operations, impact of, and timing of certain projects, timing of and effects of drilling, tie-in and completion of wells, the effect of government announcements, proposals and legislation, plans regarding hedging, wells to be drilled, expected or anticipated production rates, timing of expected production increases, the weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportation costs and other costs and expenses, planned disposition of Saskatchewan assets and use of proceeds and timing thereof, maintenance of productive capacity and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. The recovery and reserve estimates of True's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of True. The reader is cautioned not to place undue reliance on this forward looking information. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect True's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at True's website (www.trueenergytrust.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and True does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes.

Fourth Quarter 2007

Funds flow from operations during the fourth quarter of 2007 was $19.5 million, a decrease of 39% compared to $31.8 million for the fourth quarter of 2006. This is primarily reflective of reduced sales volumes in fourth quarter 2007 compared to the same period in 2006, offset partially by an overall increase in commodity prices between those periods. By comparison, in the last quarter of 2007, True had a net loss of $0.4 million compared to a net loss of $250.7 million in the fourth quarter of 2006. During the fourth quarter of 2007, a $9.3 million future income tax recovery was recorded to reflect the tax rate changes which were enacted by the Government of Canada during the period. The net loss during the fourth quarter of 2006 included non-cash charges of a ceiling test write down of $110 million and a goodwill impairment charge of $169.8 million.

Sales volumes for the three months ended December 31, 2007 averaged 14,937 boe/d, down 24% from the 19,747 boe/d produced in the fourth quarter of 2006. Production during the last quarter of 2006 included the additional volumes derived from the Shellbridge Oil & Gas, Inc. ("Shellbridge") and Prairie Schooner Petroleum Ltd. ("Prairie Schooner") acquisitions as well as drilling activity during 2006. Fourth quarter 2007 sales volumes were lower than the same period in 2006 due to natural production declines, decreased production due to property dispositions during 2007, the delay of tie-in and completion of certain third party first quarter drilled wells until late in 2007, and the impact of slowly increasing production for the Kerrobert SAGD expansion project, which will continue to advance into 2008. The SAGD response on the Kerrobert project was slower than estimated, however, advancement of the project continues. Four (1.0 net) third party operated wells from first quarter 2007 drilling in the Ferrier area were completed and tied in during the fourth quarter of 2007. Current production from these wells total approximately 85 boe/d net.

In the fourth quarter of 2007, average sales volumes increased 6% from the third quarter 2007 average volumes of 14,096 boe/d as a result of the resumption of certain production following plant turnarounds and other challenges experienced in the third quarter of 2007. Fourth quarter 2007 volumes were also lower than anticipated due to non-operated well and facility downtime, certain shut-in production for facility modifications, and the impact of cold weather on operations late in the fourth quarter. Natural gas sales averaged 57.4 Mmcf/d during the last quarter of 2007, compared to 64.9 Mmcf/d in the fourth quarter of 2006. The weighting toward natural gas averaged 64% in the fourth quarter, compared to 62% in the corresponding period of 2006. In the last quarter of 2007, True's natural gas exploration efforts focused on drilling 3 (1.0 net) non-operated natural gas wells in the Ferrier, Alberta area. Crude oil, condensate and NGL sales volumes averaged 5,370 bbls/d in the fourth quarter compared to 7,440 bbls/d during the same period of 2006. During the fourth quarter of 2007, True invested $15.5 million on capital projects, excluding corporate and asset acquisitions and dispositions, compared to $25.5 million in 2006.

During the fourth quarter of 2007, True experienced an overall increase in commodity prices, based on increases in crude oil, condensate and NGL pricing, as compared to the same period in 2006. The average Alberta Spot price for natural gas during this quarter was 11% lower than in the same period in 2006. For the three months ending December 31, 2007, True received an average natural gas price, before transportation and hedging, of $6.40/Mcf, 8% less than $6.98/Mcf in the same period in 2006 and 18% higher than $5.44/Mcf in the third quarter of 2007. For heavy crude oil, True received an average price before transportation of $39.72/bbl during the fourth quarter of 2007, 14% more than $34.82/bbl in the same period in 2006 and 6% less than $42.30/bbl in the third quarter of 2007. In comparison, the average reference price for Hardisty Heavy crude in the fourth quarter of 2007 was 22% more than the average 2006 price in the same period. For light oil, condensate and NGLs, True received an average price of $78.42/bbl before hedging during the last quarter of 2007, 30% more than the average price of $60.34/bbl received in the same period of 2006, compared to a 34% increase in the Edmonton par reference price. The average price for light oil, condensate and NGLs for True was 3% lower than the $76.37/bbl for the third quarter of 2007. During the fourth quarter of 2007, pre-transportation revenue of $60.4 million was 21% less than the corresponding 2006 period.

In the fourth quarter of 2007, the Trust paid $12.6 million in royalties, compared to $18.5 million in the same period in 2006. As a percentage of pre-hedge sales (after transportation costs), royalties were 22% in the fourth quarter of 2007 compared to 25% in the same period in 2006. In this same period of 2007, operating costs totaled $16.5 million, compared to $17.7 million recorded in the same period of 2006. During the fourth quarter of 2007, operating costs averaged $12.01/boe, up from the $9.76/boe incurred during the fourth quarter of 2006, primarily reflecting the fixed component of operating costs combined with the reduced sales volumes between comparable periods. In comparison, operating costs for the third quarter of 2007 averaged $13.13/boe. True is forecasting operating costs of approximately $11.75/boe in 2008. During the fourth quarter of 2007, company field operating netbacks decreased by 3% to $20.51/boe compared to 2006, driven primarily by increased operating costs, offset partially by increased overall commodity prices and decreased royalties. In comparison, the company field operating netback for the third quarter of 2007 was $15.76/boe. Field operating netbacks for natural gas before hedging during the fourth quarter of 2007 of $2.78/Mcf were 27% less than the 2006 netbacks, reflecting a significantly lower gas price, increases in transportation and operating expenses, offset partially by a reduction in royalties. In comparison, the field operating netback for natural gas for the third quarter of 2007 was $2.05/Mcf. Field operating netbacks before hedging for crude oil and NGLs during the fourth quarter of 2007 averaged $27.34/bbl, up from $18.34/bbl during the fourth quarter of 2006, primarily as a result of a significant increase in the overall commodity price received, partially offset by higher operating costs and royalties. In comparison, the field operating netback for crude oil and NGLs for the third quarter of 2007 was $24.71/bbl.

In the fourth quarter of 2007, the net cost of general and administrative expenses was $4.7 million, compared to $5.9 million in the comparable 2006 period reflecting a reduction of the number of salaried personnel on staff and other efforts to reduce costs.

Depletion, depreciation and accretion expense for the fourth quarter of 2007 was $39.8 million, compared to $53.1 million in 2006, which reflects reduced carrying costs in 2007, combined with lower production volumes in fourth quarter 2007 versus 2006.

Net Income (Loss) and Funds Flow from Operations

True generated funds flow from operations of $101.2 million ($1.33 per diluted unit) for the year ended December 31, 2007, up 12% from the $90.4 million ($1.87 per diluted unit) for the 2006 year. The increase in funds flow from operations for the 2007 year was primarily the result of higher sales volumes, offset by marginally lower overall commodity prices and operating netbacks for 2007.

The net loss for the 2007 year was $24.3 million compared to a net loss of $233.6 million in 2006. The 2006 year included fourth quarter non-cash charges for the ceiling test write-down of property, plant and equipment of $110.0 million and goodwill impairment of $169.8 million.

Funds Flow From Operations and Net Income

	Years ended December 31,	
($000s, except per unit amounts)	2007	2006
Funds flow from operations	101,172	90,391
Basic ($/unit)	1.33	1.91
Diluted ($/unit)	1.33	1.87
Net income (loss)	(24,267)	(233,564)
Basic ($/unit)	(0.32)	(4.95)
Diluted ($/unit)	(0.32)	(4.95)

Reconciliation of Funds Flow from Operations and Cash Flow from Operating Activities

($000s, except per unit amounts)	Years ended December 31, 2007	2006
Funds flow from operations	101,172	90,391
Asset retirement costs incurred	(835)	(516)
Change in non-cash working capital	(18,131)	36,925
Cash flow from operating activities	82,206	126,800

Sales Volumes

Sales volumes for the year ended December 31, 2007 averaged 16,139 boe/d as compared to 13,861 boe/d for the 2006 year, representing a 16% increase.

This reflects the timing of additional production from the closing of the acquisitions of Shellbridge on June 23, 2006 and Prairie Schooner on September 22, 2006, in addition to the impact from drilling and operational activity in 2007.

Sales Volumes

		Years ended December 31, 2007	2006
Natural gas	(mcf/d)	64,853	51,264
Heavy oil	(bbls/d)	3,450	3,612
Light oil and condensate	(bbls/d)	1,289	1,285
NGLs	(bbls/d)	591	420
Total crude oil and NGLs	(bbls/d)	5,330	5,317
Total boe/d	(6:1)	16,139	13,861

Field production estimates for the first quarter of 2008 are expected to average approximately 13,200 boe/d. Field production was adversely impacted by the extreme weather experienced in January and February of 2008. In addition, an unplanned third party plant outage impacted production in west central Alberta for February 2008. Work is underway to deal with a well servicing and equipment repair backlog.

During the 2007 year, True achieved a 98% success rate in drilling or participation in 40 (27.3 net) working interest wells, resulting in 20 (10.4 net) gas wells, 17 (14.4 net) oil wells, 2 (2.0 net) stratagraphic test oil wells and 1 (0.5 net) dry hole.

Only 6 (3.3 net) wells were drilled subsequent to the first quarter 2007 including 3 (1.0 net) third party operated wells in the fourth quarter of 2007. The Trust currently plans to drill 2 (2.0 net) operated exploration wells late in the first quarter of 2008.

Advancement of the Kerrobert SAGD project continues. During the first quarter of 2008, True has increased steam rates to the 4 new steam injectors to near maximum levels. Wellhead injection pressures have uniformly increased indicating a re-pressurization of the reservoir. Further evidence of re-pressurization has been seen through the consistent increase of wellbore fluid levels and downhole pump inlet pressures. Production well temperatures have remained at near initial reservoir levels indicating even heating is underway and that no random, premature, breakthrough has occurred – a positive indicator of overall project conformance. Based on the recovery responses of the original 1996 pilot project, estimated oil rate increases on the current project should occur 4 to 6 months after start-up. As we approach the midpoint of the 4 to 6 month timing range it is clear there will not be an "early" response, however all technical parameters continue to point to a very positive project.

For the year ended December 31, 2007, the weighting towards natural gas sales averaged 67% compared to 62% in the same period in 2006. Heavy oil sales made up 21% of total production for the 2007 year compared to 26% in 2006. The September 2006 acquisition of Prairie Schooner added significant natural gas volumes which has increased the natural gas production weighting since that date.

Sales of natural gas averaged 64.9 mmcf/d for 2007, compared to 51.3 mmcf/d in 2006, an increase of 27%. Crude oil and NGL sales for 2007 averaged 5,330 bbls/d, compared to 2006 average sales of 5,317 bbls/d.

Commodity Prices

Average Commodity Prices

	Years ended December 31, 2007	2006	% change
Exchange rate *(US$/Cdn$)*	0.9390	0.8817	7
Natural gas:			
NYMEX *(US$/mmbtu)*	7.14	6.99	2
Alberta spot *($/mcf)*	6.43	6.50	(1)
True's average price (*$/mcf)*	6.73	6.75	-
True's average price (including hedging) (*$/mcf)*	7.13	6.93	3
Crude oil:			
WTI *(US$/bbl)*	74.25	66.23	12
Edmonton par – light oil *($/bbl*)	77.06	73.30	5
Bow River – medium/heavy oil *($/bbl*)	53.16	51.54	3
Hardisty Heavy – heavy oil *($/bbl*)	44.77	43.32	3
True's average prices *($/bbl)*			
Light crude oil, condensate and NGLs	64.60	62.46	3
Light crude oil, condensate and NGLs (including hedging)	45.22	61.03	(26)
Heavy crude oil	40.05	41.17	(3)
Total crude oil and NGLs	48.71	48.00	1
Total crude oil and NGLs (including hedging)	41.88	47.54	(12)

True's natural gas is primarily sold on the daily spot market. During 2007, the AECO Spot reference price decreased by 1% compared to 2006. Similarly, True's average sales price before transportation and hedging for 2007 averaged $6.73/mcf for its natural gas, only 0.1% less than the $6.75/mcf received in 2006.

For heavy crude oil, True received an average price before transportation of $40.05/bbl during 2007, a decrease of 3% over 2006 prices. The Bow River reference price increased by 3% and the Hardisty Heavy reference price increased by 3% over the same period. The majority of True's heavy crude oil density ranges between 11 and 16 degrees API consistent with the Hardisty Heavy reference price. The primary reason for the relative decrease in True's heavy oil price received for 2006 to 2007, compared to a small increase in the Hardisty Heavy reference price is the timing of True's heavy oil sales experienced in 2007 – a weighting of higher sales volumes in the first and fourth quarters of 2007 where lower commodity prices were experienced.

For light oil, condensate and NGLs, True recorded an average $64.60/bbl before hedging during 2007, 3% higher than the average price received in 2006. During this same period, the Edmonton par price increased by 5%. The average WTI crude oil US dollar based price increased 12% from 2006 to 2007. Despite a more robust global crude oil environment in 2007, much of the positive impact in WTI crude oil pricing was offset by a strengthening Canadian dollar.

Revenue

Revenue before other income for the year ended December 31, 2007 was $254.0 million, 16% greater than the $219.4 million in 2006. The higher revenue for 2007 was the result of higher natural gas, crude oil, condensate and NGL sales volumes, despite marginally lower overall commodity prices.

	Years ended December 31,	
($000s)	2007	2006
Light crude oil, condensate and NGLs	44,325	38,876
Heavy oil	50,436	54,278
Crude oil and NGLs	94,761	93,154
Natural gas	159,278	126,216
Total revenue before other	254,039	219,370
Other [(1)]	4,451	1,543
Total revenue before royalties and hedging	258,490	220,913
Gain (loss) on commodity contracts	(3,852)	2,639
Total revenue before royalties	254,638	223,552

[(1)] Other revenue primarily consists of processing and other third party income.

Financial Instruments

The Trust has a formal risk management policy which permits management to use specified price risk management strategies for up to 50% of crude oil, natural gas and NGL production including fixed price contracts, costless collars and the purchase of floor price options and other derivative financial instruments to reduce the impact of price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to cash distributions, as well as, to ensure True realizes positive economic returns from its capital developments and acquisition activities.

The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's unitholder distributions and capital program.

A summary of the hedge volumes and average prices by quarter currently outstanding as of March 6, 2008 is shown in the following tables (see Note 20 to the consolidated financial statements for a detailed disclosure of all commodity contracts in place as at March 6, 2008):

Crude oil and liquids **Average Volumes (bbls/d)**

	Q1 2008	Q2-Q3 2008	Q4 2008	Q1 2009	Q2 2009
Costless collars	2,000	2,000	2,000	-	-
Total bbls/d	2,000	2,000	2,000	-	-

Average Price (US$/bbl WTI)

	Q1 2008	Q2-Q3 2008	Q4 2008	Q1 2009	Q2 2009
Collar ceiling price	75.00	82.00	82.00	-	-
Collar floor price	65.00	65.00	65.00	-	-

Natural gas	**Average Volumes (GJ/d)**				
	Q1 2008	Q2-Q3 2008	Q4 2008	Q1 2009	Q2 2009
Costless collars	5,000	-	-	-	-
Fixed	15,551	24,326	24,326	10,550	10,550
Total GJ/d	20,551	24,326	24,326	10,550	10,550

Average Price ($/GJ AECO C)					
	Q1 2008	Q2-Q3 2008	Q4 2008	Q1 2009	Q2 2009
Collar ceiling price	9.05	-	-	-	-
Collar floor price	8.00	-	-	-	-
Fixed	6.65	6.68	6.89	7.74	7.01

The following is a summary of the gain (loss) on commodity contracts for the years ended December 31, 2007 and 2006:

Commodity contracts

($000s)	Crude Oil & Liquids	Natural Gas	2007 Total
Realized cash gain (loss) on contracts [1]	(1,891)	8,382	6,491
Unrealized gain (loss) on contracts	(11,404)	1,061	(10,343)
Total gain (loss) on commodity contracts	(13,295)	9,443	(3,852)

($000s)	Crude Oil & Liquids	Natural Gas	2006 Total
Realized cash gain (loss) on contracts [2]	(890)	3,529	2,639
Unrealized gain (loss) on contracts	-	-	-
Total gain (loss) on commodity contracts	(890)	3,529	2,639

(1) Includes crude oil and natural gas commodity contract premiums expensed in the year and the amortization of prior year crude oil and natural gas commodity contract premiums of a total $3.7 million for year ended December 31, 2007.

(2) Includes the amortization of crude oil and natural gas commodity contract premiums of a total $1.8 million for the year ended December 31, 2006.

Effective January 1, 2007, new accounting standards were implemented relating to financial instruments. The impacts of adopting the new standards are reflected in the Trust's results for the year ended December 31, 2007. Prior year comparative financial statements have not been restated. For a description of the new accounting standards and the impact on the Trust's financial statements of adopting such rules, including the impact on the Trust's prepaid expenses, deferred financing charges, long-term debt, convertible debentures and unrealized gains on commodity contracts, refer to note 3 of the consolidated financial statements of the Trust for year ended December 31, 2007.

Royalties

For the year ended December 31, 2007, total royalties were $47.0 million, compared to $51.8 million incurred in 2006. Overall royalties as a percentage of revenue (after transportation costs) in 2007 were 19%, compared with 24% in 2006. Royalties for 2007 include the impact of the reversal of certain over accruals for heavy crude oil and natural gas royalties from periods prior to 2007 of approximately $5.5 million, including adjustments primarily recognized in the second quarter of 2007. Based upon the latest and most up-to-date information and experience, it was determined that certain prior period royalty accrual estimates were overstated by approximately 2% per month on average as a percentage of revenue after transportation costs.

Royalties by Commodity Type	Years ended December 31,	
($000s, except where noted)	2007	2006
Light crude oil, condensate and NGLs	9,772	6,707
$/bbl	14.24	10.77
Average light crude oil, condensate, and NGLs royalty rate (%)	22	18
Heavy Oil	6,867	14,395
$/bbl	5.45	10.91
Average heavy oil royalty rate (%)	14	28
Natural Gas	30,365	30,714
$/mcf	1.28	1.64
Average natural gas royalty rate (%)	20	25
Total	47,004	51,816
$/boe	7.98	10.24
Average total royalty rate (%)	19	24

Royalties, by Type

	Years ended December 31,	
($000s)	2007	2006
Crown royalties, net of ARTC	20,799	32,243
Indian Oil and Gas Canada royalties	5,927	2,948
Freehold & GORR	20,278	16,625
Total	47,004	51,816

Expenses

	Years ended December 31,	
($000s)	2007	2006
Production	68,282	46,685
Transportation	7,938	6,517
General and administrative	18,186	14,896
Interest and financing charges	18,108	10,665
Unit-based compensation	901	6,597

Expenses per boe

	Years ended December 31,	
($ per boe)	2007	2006
Production	11.59	9.23
Transportation	1.35	1.29
General and administrative	3.09	2.94
Interest and financing charges	3.07	2.11
Unit-based compensation	0.15	1.30

Production Expenses

For the year ended December 31, 2007, production expenses totaled $68.3 million, compared to $46.6 million recorded in 2006. During 2007, production expenses averaged $11.59/boe, compared to $9.23/boe over the same period in 2006. The increase in 2007 costs on a boe basis was mainly due to a significant fixed component of production expenses and the combination of substantially reduced production volumes primarily in the third and fourth quarters of 2007. Production expenses for 2007 also include approximately $4.4 million ($0.76/boe) of costs related to 2006, including primarily additional costs recognized in the second quarter of 2007; excluding this impact, production expenses for 2007 would have been approximately $10.83/boe.

Production expenses are expected to increase in the first quarter of 2008 as additional natural gas input costs continue to be required to operate the Kerrobert SAGD facility after startup in late 2007. To mitigate expected increases in natural gas fuel costs through the first quarter of 2008, True has negotiated fixed price fuel purchase contracts, with contract remaining of 2,000 GJ/day of natural gas for $6.415/GJ for the months of November 2007 to March 2008.

Production Expenses, by Commodity Type

	Years ended December 31,	
($000s, except where noted)	2007	2006
Light crude oil, condensate and NGLs	9,906	7,873
$/bbl	14.44	12.65
Heavy oil	18,301	13,754
$/bbl	14.53	10.43
Natural gas	40,075	25,058
$/mcf	1.69	1.34
Total	68,282	46,685
$/boe	11.59	9.23
Total	68,282	46,685
Processing and other third party income [1]	(4,402)	(1,336)
Total after deducting processing and other third party income	63,880	45,349
$/boe	10.84	8.96

[1] Processing and other third party income is included within petroleum and natural gas sales on the statement of income.

Transportation

Transportation costs continue to be approximately 2 to 3% of gross revenues for the years ended December 31, 2007 and 2006.

Operating Netback

For the 2007, corporate field operating netback (before hedging) was $22.21/boe compared to $22.60/boe in 2006. This was the result of marginally reduced overall commodity prices, higher operating costs experienced in the year, offset by reduced average royalties. After including hedging activities, the corporate field operating netback for 2007 was $21.55/boe compared to $23.12/boe in 2006.

Field Operating Netback – Corporate (before hedging)

	Years ended December 31,	
($/boe)	2007	2006
Sales	43.13	43.36
Transportation	(1.35)	(1.29)
Royalties	(7.98)	(10.24)
Production expense	(11.59)	(9.23)
Field operating netback	22.21	22.60

Field operating netback for natural gas for 2007 decreased 3% to $3.47/mcf, compared to $3.59/mcf for 2006, reflecting the marginally weaker natural gas prices experienced, in addition to higher production costs, the effects of which were partially offset by lower royalties. After including hedging activities, field operating netback for natural gas for 2007 was $3.87/mcf compared to $3.77/mcf in 2006.

Field Operating Netback - Natural Gas (before hedging)

	Years ended December 31,	
($/mcf)	2007	2006
Sales	6.73	6.75
Transportation	(0.29)	(0.18)
Royalties	(1.28)	(1.64)
Production expense	(1.69)	(1.34)
Field operating netback	3.47	3.59

Field operating netback for crude oil and NGLs averaged $25.01/bbl for 2007, up 3% compared to $24.36/bbl for 2006, compared to a 1% increase in the crude oil and NGLs sales price. After including hedging activities, field operating netback for crude oil and NGLs for 2007 was $18.17/boe compared to $23.90/boe in 2006; the loss on commodity contracts for 2007 includes $11.4 million of unrealized crude oil hedging losses valued at December 31, 2007.

Field Operating Netback - Crude Oil and NGLs (before hedging)

	Years ended December 31,	
($/bbl)	2007	2006
Sales	48.71	48.00
Transportation	(0.65)	(1.63)
Royalties	(8.55)	(10.87)
Production expense	(14.50)	(11.14)
Field operating netback	25.01	24.36

General and Administrative

Net general and administrative ("G&A") expenses for 2007 were $18.2 million compared to $14.9 million for 2006. The increase in the G&A expense from 2006 to 2007 is consistent with the increase in staffing levels, higher compensation and other administrative costs as a result of two acquisitions completed in 2006. G&A for 2007 includes severance costs of approximately $1.1 million. On a per boe basis, G&A expenses were $3.09/boe for 2007 compared to $2.94/boe for 2006. The increase in G&A on a per boe basis is consistent with reduced sales volumes experienced during the third and fourth quarters of 2007 compared to earlier in 2007 and the fourth quarter of 2006.

General and Administrative Expenses

	Years ended December 31,	
($000s, except where noted)	2007	2006
Gross expenses	24,191	19,702
Capitalized	(3,881)	(2,640)
Recoveries	(2,124)	(2,166)
Net expenses	18,186	14,896
Net expenses, per unit ($/boe)	3.09	2.94

G&A expenses for the year ended December 31, 2007 do not include the costs of the March 30, 2007 Annual and Special Meeting, which are presented separately on the statement of income and discussed in the Special Meeting Costs section of this report.

Interest and Financing Charges

True recorded $18.1 million of interest and financing charges in the year ended December 31, 2007 compared to $10.7 million in 2006. The increase in interest and financing charges for 2007 compared to 2006 is consistent with the increase in bank debt. True's net debt at December 31, 2007 of $251.2 million includes the $79.4 million liability portion of convertible debentures, $168.5 million of bank debt and the balance a working capital deficiency.

Interest and Financing Charges

	Years ended December 31,	
($000s, except where noted)	2007	2006
Interest and financing charges	18,108	10,665
Interest and financing charges *($/boe)*	3.07	2.11
Net debt (1) including convertible debentures at quarter end	251,163	275,816
Debt to periods funds flow from operations ratio annualized (2)	3.2x	2.1x
Net debt excluding convertible debentures at quarter end	171,756	194,265
Debt to periods funds flow from operations ratio annualized (2)	2.2x	1.5x

[(1)] Net debt includes the net working capital deficiency before short-term commodity contract assets and liabilities and short-term future tax assets. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.

[(2)] Debt to funds flow from operations ratio is calculated based upon fourth quarter funds flow from operations annualized.

Unit-Based Compensation

Non-cash unit-based compensation expense for the year ended December 31, 2007 was $2.0 million compared to $6.6 million in 2006. The decrease in the 2007 expense reflects a reduction in the estimated weighted average fair value of incentive rights granted for more recent options, a reduction to the 2007 expense of $1.8 million for a reversal of prior year unit-based compensation expense for 2007 forfeitures of unvested incentive rights and slightly reduced incentive rights being granted in 2007 compared to 2006.

Capital Expenditures

True invested $87.4 million on exploration and development activities during 2007, compared to $98.7 million in 2006. True reduced its 2007 capital program in Western Canada in response to high costs and weaker commodity prices. Following the execution of True's extensive Q1 2007 drilling program of 34 (24.0 net) wells, the main focus for the second, third and fourth quarters of 2007 was on completions and tie-ins of first quarter drills and further upgrades to the Kerrobert SAGD facility. During the 2007 year, True achieved a 98% success rate in drilling or participation in 40 (27.3 net) working interest wells, resulting in 20 (10.4 net) gas wells, 17 (14.4 net) oil wells, 2 (2 net) stratagraphic test wells and 1 (0.5 net) dry hole. During the fourth quarter of 2007, True successfully drilled 3 (1.0 net) natural gas wells in the Ferrier area of Alberta.

Capital Expenditures [(1)]

($000s)	Years ended December 31, 2007	2006
Lease acquisitions and retention	2,084	9,056
Geological and geophysical	4,275	2,399
Drilling and completion costs	64,688	68,702
Facilities and equipment	15,294	18,533
Other capital [(2)]	1,056	-
Exploration and development	87,397	98,690
Corporate and property acquisitions	1,505	17,322
Total capital expenditures – cash	88,902	116,012
Property dispositions – cash	(31,808)	(24,514)
Total net capital expenditures – cash	57,094	91,498
Corporate acquisitions – non-cash	-	482,875
Property acquisitions – non-cash [(3)]	-	1,817
Other – non-cash [(4)]	270	3,006
Corporate acquisitions and other	270	487,698
Total capital expenditures	57,364	579,196

(1) Excludes capitalized costs related to asset retirement obligation expenditures incurred during the year.
(2) Other capital for 2007 include natural gas input costs incurred during the initial "warm-up" phase at the Kerrobert SAGD expansion project.
(3) Includes consideration paid for the acquisition of a property interest by issue of trust units.
(4) Other includes current period's asset retirement obligations and unit based compensation capitalized.

Approximately 31 percent of the $88.9 million capital program was financed with funds flow from operations compared to nil in 2006. The remainder of the program was financed through a combination of property dispositions and debt and equity financings.

True holds an extensive land base. At December 31, 2007, True had approximately 537,800 net undeveloped acres of land of its total developed and undeveloped net acreage position of 936,400 net acres in Saskatchewan, Alberta, and British Columbia.

Dispositions during 2007 consist of seven separate oil and gas property sales involving areas outside of the Trust's core areas for future development. The net proceeds received on these property sales after adjustments was an aggregate of $31.8 million.

At the end of the fourth quarter of 2007, the Trust had committed to drill a total of 2 wells in Alberta with varying commitment dates up to the end of the third quarter of 2008 pursuant to various farm-in agreements with oil and gas companies. True expects to satisfy these various drilling commitments at an estimated cost for True's interest of approximately $2.8 million.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for 2007 was $171.5 million ($29.11/boe), compared to the $138.9 million ($27.45/boe) in 2006, reflecting the acquisition of Prairie Schooner in September 2006 in conjunction with increased production volumes and True's active drilling program over 2006 and 2007.

For the year ended December 31, 2007, True has included $56.6 million for future development costs in the depletion calculation and excluded from the depletion calculation $37.8 million for undeveloped land and $47.6 million for estimated salvage.

Depletion, Depreciation and Accretion Costs

	Years ended December 31,	
($000s, except where noted)	2007	2006
Depletion and Depreciation	169,347	137,810
Accretion	2,137	1,065
Total	171,484	138,875
Per unit ($/boe)	29.11	27.45

Ceiling Test

The Trust calculates a ceiling test quarterly and annually to place a limit on the aggregate carrying value of its capitalized costs, which may be amortized against revenues of future periods. The ceiling test is performed in accordance with the requirements of the Canadian Institute of Chartered Accountants ("CICA") AcG-16 "Oil and Gas Accounting – Full Cost, a two step process.

The Trust performed a ceiling test calculation at December 31, 2007 resulting in undiscounted cash flows from proved reserves and the undeveloped properties not exceeding the carrying value of oil and gas assets. Consequently, True performed stage two of the ceiling test assessing whether discounted future cash flows from the production of proved plus probable reserves plus the carrying cost of undeveloped properties, net of any impairment allowance, exceeds the carrying value of its petroleum and natural gas properties. No impairment in oil and gas assets was identified as at December 31, 2007.

The ceiling test calculation will be updated in 2008 on a quarterly and annual basis based upon the latest available data, including but not limited to an updated annual external reserve engineering report which incorporates a full evaluation of reserves or internal reserve updates at quarterly periods, and the latest commodity pricing deck. The closing of the proposed Saskatchewan asset divestiture will impact the determination of reserves for purposes of the calculation of depletion, a potential gain (loss) on disposal of petroleum and natural gas properties and the ceiling test. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. Changes in these judgments and estimates and other variables associated with the closing of the proposed Saskatchewan asset divestiture could have a material impact on the calculations of depletion, a potential gain (loss) on disposal of petroleum and natural gas properties and the ceiling test.

In 2006, as a result of performing this test, a ceiling test impairment of $110.0 million was recorded as a write-down of petroleum and natural gas properties in the consolidated statements of operations and was included in accumulated depletion.

Goodwill

Goodwill represents the excess of total consideration paid plus the future income tax liability less the fair value of the net identifiable assets acquired in each acquisition transaction. Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired.

The Trust reviewed the valuation of goodwill as of December 31, 2006 based upon the latest available data. Based upon this review, an impairment of all remaining goodwill in the amount of $169.8 million was recorded as a non-cash charge to income as of December 31, 2006.

Special Meeting Costs

On January 15, 2007, the Trust announced its proposal to convert into an intermediate exploration and production company (the “Reorganization”). Pursuant to the Reorganization, it was contemplated that holders of trust units of the Trust would receive an equal number of common shares of a newly formed corporation that will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares were also to be exchanged for common shares based on the conversion ratio thereof. The Reorganization was subject to all required regulatory approvals and securityholder approval by at least 66 2/3% of the votes cast by unitholders of the Trust and holders of the exchangeable shares. At the Special and Annual Meeting held on March 30, 2007, the special resolution related to the Reorganization was not approved. As a result, the Reorganization was not completed.

The Trust incurred $3.8 million in costs for legal, financial advisory, accounting, unitholder solicitation services, printing, mailing and other expenses that are included as special meeting costs within the statement of income for the year ended December 31, 2007.

Asset Retirement Obligations

As at December 31, 2007, the Trust has recorded an Asset Retirement Obligation (“ARO”) of $28.4 million, compared to $26.6 million at December 31, 2006, for future abandonment and reclamation of the Trust’s properties. For the year ended December 31, 2007, the ARO increased by $1.8 million total as a result of accretion expense of $2.1 million, and $1.4 million net changes in estimates and liabilities incurred on development activities, offset by $0.9 million of liabilities released on dispositions and $0.8 million of liabilities settled during the year.

Income Taxes

For the year ended December 31, 2007, the Trust has recorded capital tax expense of $2.0 million compared to $3.2 million expensed in 2006. Capital taxes are based on debt and equity levels of the Trust at the end of the year in addition to a resource surcharge component of provincial taxes calculated as a percentage of revenues. In the second quarter of 2006, the federal government enacted legislation that eliminates federal capital tax, retroactive to January 1, 2006. As a result, since that date capital taxes are based on only provincial capital taxes.

Future income taxes arise from differences between the accounting and tax bases of the Trust’s assets and liabilities. For the year ended December 31, 2007, the Trust recognized a future income tax recovery of $59.8 million compared to a recovery of $101.1 million in 2006. On April 10, 2006 the Alberta government enacted a decrease of 1.5 percent to the provincial corporate tax rate. On June 6, 2006 the federal government enacted a two percent decrease to the federal corporate tax rate from January 1, 2008 to January 1, 2010 and an elimination of the 1.12 percent federal surtax at January 1, 2008. On June 12, 2007, the federal government further reduced the general corporate tax rate by 0.5 percent starting 2011. Further as indicated on October 30, 2007 and enacted on December 14, 2007, the federal government announced changes to the tax system including reduction of the corporate income tax rate from 22.1 percent to 15 percent by 2012, with these reductions to be phased in between 2008 and 2012. The reduction in the general corporate tax rate will also apply to the taxation of Income Trusts, reducing the combined federal and deemed provincial tax rate for distributions to 28 percent in 2012. During the fourth quarter of 2007, a $9.3 million future income tax recovery was recorded to reflect these substantively enacted tax rates.

Under our current structure, the operating entities make interest and royalty payments to the Trust, which transfers taxable income to the Trust to eliminate income subject to corporate and other income taxes in the operating entities. With the new legislation (as referred to below), such amounts transferred to the Trust could be taxable beginning in 2011 as distributions will no longer be deductible for income tax purposes. At that time, True could claim tax pools in its operating companies, reduce the income transferred to the Trust, and pay all or a portion of distributions as a return of capital basis. Until 2011, under the terms of its trust indenture, the Trust is required to distribute amounts equal to at least its taxable income. In the event that the Trust has undistributed taxable income in a taxation year (prior to 2011), an additional special taxable distribution, subject to certain withholding taxes, would be required by the terms of its trust indenture.

The estimate of future taxes is based on the current tax status of the Trust. Future events, which could materially affect future income taxes such as acquisitions and dispositions and modifications to the distribution policy, are not reflected under Canadian GAAP until the events occur and the related legal requirements have been fulfilled. As a result, future changes to the tax legislation could lead to a material change in the recorded amount of future income taxes.

The new legislation is not expected to directly affect our cash flow levels and distribution policies until 2011 at the earliest.

Enactment of the Tax on Income Trusts

On June 12, 2007, the legislation implementing the new tax (the “SIFT tax”) on publicly traded income trusts and limited partnerships, referred to as “Specified investment flow-through” (“SIFTs”) entities (Bill C-52) received third reading in the House of Commons and on June 22, 2007, Bill C-52 received Royal assent. As a result, the SIFT tax was considered to be enacted for accounting purposes in June 2007, which resulted in a $1.2 million future income tax recovery amount being recorded to reflect current temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. The SIFT tax announcement and the related future income tax recovery did not affect cash flow or distributions and is not expected to affect distribution policies until 2011 at the earliest.

SIFTs are certain publicly traded income and royalty trusts and limited partnerships including True. For SIFTs in existence on October 31, 2006 the SIFT tax will be effective in 2011, unless certain rules related to “undue expansion” are not adhered to. Under the guidance provided, True can increase its equity by approximately $737 million between now and 2011 without prematurely triggering the SIFT tax.

Under the current SIFT tax rules, distributions from certain types of income will not be deductible for income tax purposes by SIFTs in 2011, and thereafter, and any resultant trust level taxable income will be taxed at a SIFT tax rate which will be the federal general corporate income tax rate plus the provincial SIFT tax factor (which is set at a fixed rate of 13%). The SIFT tax rate was initially proposed at 31.5 percent; however, on October 30, 2007, the Government of Canada, in its Mini-Budget (Bill C-28), proposed reductions to the general corporate tax rate, thereby reducing the SIFT rate to 29.5 percent in 2011 and 28.0 percent in 2012 and later. On December 14, 2007, Bill C-28 received royal assent, resulting in a reduction to the SIFT tax rate as it becomes effective in 2011, and lowering the rate at which any corporate income taxes will be paid by True’s operating entities. As the Trust currently has a significant tax pool base and expects to increase its tax pool base until 2011, it is expected that the Trust could shelter its taxable income for a period after the effective date of the SIFT tax. Distributions of this nature would not be currently taxable to unitholders as they would represent a return of capital that would continue to be an adjustment to a unitholder's adjusted cost base of trust units. Distributions from income subject to the SIFT tax will be considered taxable dividends to unitholders and will generally be eligible for the dividend tax credit. As a result, the SIFT tax will not adversely affect Canadian investors who hold True units in a non-tax deferred account.

On February 26, 2008, the Federal Minister of Finance announced (the "Provincial SIFT Tax Proposal") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal the Trust would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the trust tax legislation. As part of the announcement the Minister indicated that the federal government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequences to investors or the Trust.

The True Board of Directors and Management continue to review the impact of this tax on business strategy. At the present time, True believes some or all of the following actions will or could result due to the enactment of the SIFT tax:

- If structural or other similar changes are not made, the distribution yield net of the SIFT tax in 2011 and beyond to taxable Canadian investors will remain approximately the same; however, the distribution yield to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) would fall by an estimated 29.5 percent in 2011 and 28.0 percent in 2012 and beyond. For U.S. investors, the distribution yield net of the SIFT and withholding taxes would fall by an estimated 25.1 percent in 2011 and 23.8 percent in 2012 and beyond;
- A portion of True's cash flow could be allocated to the payment of the SIFT tax, or other forms of tax, and would not be available for distribution or re-investment;
- True could convert to a corporate structure to facilitate investing a higher proportion or all of its cash flow in exploration and development projects. Such a conversion and change to capital programs could result in a significant reduction to or elimination of distributions and/or dividends;
- True might determine that it is more economic to remain in the trust structure, at least for a period of time, and shelter its taxable income using tax pools and pay all or a portion of its distributions on a return of capital basis, likely at a lower payout ratio. Further, as the SIFT tax rate exceeds the corporate income tax rate that would be applicable to True, some corporate tax might be paid resulting in all or a portion of distributions being paid on a return of capital basis at a lower payout ratio.

The Trust is reviewing all organizational structures and alternatives to minimize the impact of the SIFT tax on our unitholders. While there can be no assurance that the negative effect of the tax can be minimized or eliminated, True and its advisors will continue to work diligently on these issues.

As at December 31, 2007, the operating subsidiaries and the Trust itself have a total future income tax liability balance of $64.3 million. Canadian GAAP requires that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools.

At December 31, 2007 the Trust and operating subsidiaries of the Trust had approximately $531 million, net of partnership deferrals, in tax pools available for deduction against future income as follows:

($000s)	Trust	Operating subsidiaries	Total
Intangible resource pools	15,000	328,000	343,000
Undepreciated capital cost	-	143,000	143,000
Loss carryforwards (expire through 2027)	-	35,000	35,000
Unit issue costs	6,000	4,000	10,000
	21,000	**510,000**	**531,000**

Distributions

Trust unitholders who held their trust units throughout 2007 received distributions of $0.96 per unit. For the year ended December 31, 2007 the Trust declared $73.5 million in total distributions as follows:

($000s, except per unit amount) Year ended December 31, 2007	Distribution Per Unit	Total
Distributions declared	$ 0.96	$ 73,451

Distribution Paid History (1)

Distributions comprise a taxable portion and a return of capital portion (tax deferred). The return of capital component reduces the cost basis of the trust units held, as described below. For additional information, please see our website at www.trueenergytrust.com.

Calendar Year	Distributions per unit	Taxable Portion	Return of Capital
2005 (two months) (2)	$ 0.480	$ 0.456	$ 0.024
2006	2.640	2.033	0.607
Cumulative to Dec. 31, 2006	$ 3.120	$ 2.489	$ 0.631
2007 year (3)	0.960	0.960	-
Cumulative to Dec. 31, 2007	$ 4.080	$ 3.449	$ 0.631
2008 year to date (two months) (4)	0.080		
Cumulative to Feb. 29, 2008	$4.160		

(1) Applies to unitholders who are residents of Canada and hold their trust units as capital property.

(2) Based upon the distributions paid in the 2005 calendar year, after the November 2, 2005 Arrangement with TKE Energy Trust.

(3) For Canadian tax purposes, 2007 distributions were determined to be 100% taxable.

In consultation with its U.S. tax advisors, True believes that its trust units should be “qualified dividends” for U.S. federal purposes. As such, the portion of distributions made during 2007 that are considered dividends for U.S. federal purposes should qualify for the reduced rate of tax applicable to long-term capital gains. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding True units. Please view our February 27, 2008 press release addressing this.

(4) It is currently estimated that the approximate taxable portion of 2008 distributions to Canadian unitholders will be between 90 to 100%. Any non-taxable amounts will be treated as a tax deferred return of capital, or an adjustment to the cost base of the units. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow from operations experienced throughout the year.

Monthly Distributions

Actual distributions paid and declared per trust unit along with relevant payment dates for 2007 to date are as follows:

Ex-distribution Date	Record Date	Payment Date	Distribution per unit
December 27, 2006	December 31, 2006	January 15, 2007	$ 0.12
January 29, 2007	January 31, 2007	February 15, 2007	0.12
February 26, 2007	February 28, 2007	March 15, 2007	0.12
April 26, 2007	April 30, 2007	May 15, 2007	0.08
May 29, 2007	May 31, 2007	June 15, 2007	0.08
June 27, 2007	June 29, 2007	July 16, 2007	0.08
July 27, 2007	July 31, 2007	August 15, 2007	0.08
August 29, 2007	August 31, 2007	September 17, 2007	0.08
September 26, 2007	September 28, 2007	October 15, 2007	0.08
October 29, 2007	October 31, 2007	November 15, 2007	0.08
November 28, 2007	November 30, 2007	December 17, 2007	0.08
December 27, 2007	December 31, 2007	January 15, 2008	0.08

During 2007, the distributions were funded directly from funds flow from operations.

On January 15, 2007, the Trust announced its intention to convert to a growth oriented, dividend paying intermediate exploration and production company (the "Reorganization"), which was voted upon by securityholders at an Annual and Special Meeting (the “Meeting”) held on March 30, 2007. Further as announced on February 15, 2007, the Board of True determined that no distribution would be declared for the month of March 2007, which would normally have been paid on April 16, 2007 to unitholders of record as at March 30, 2007, pending the consideration of the Reorganization at the Meeting. As a result of the outcome of the Meeting, wherein the Reorganization was not approved, True remains a trust.

In the second, third, and fourth quarters of 2007, monthly distributions of $0.08 per unit were declared and paid. On December 17, 2007, the Trust announced that the Board has set the distribution policy for the first quarter of 2008 at a monthly distribution rate of $0.04 per unit, subject to monthly confirmation by the Board of Directors, based on current commodity prices, hedging program, anticipated production volumes and market conditions. True anticipates that this reduction will allow the Trust’s distributions to be sustainable in the current gas price, foreign exchange rate and cost environment.

The Premium Distribution™ Reinvestment, Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP") was implemented effective March 27, 2006. Funds reinvested in the Trust through this plan were available to fund capital and other expenditures. On November 16, 2006, the Trust announced the suspension of equity available for reinvestment under DRIP until further notice.

Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, The Trust estimates that, as of February 21, 2008 approximately 29 percent of unitholders are non-Canadian residents with the remaining 71 percent being Canadian residents. True’s trust indenture provides that not more than 40 percent of its trust units can be held by non-Canadian residents.

Liquidity and Capital Resources

True’s net debt as at December 31, 2007 was $251.2 million, representing $168.5 million outstanding on the credit facility, $79.4 million in convertible debentures (liability component) and the balance a working capital deficiency.

During the year ended December 31, 2007, the Trust has reduced its net debt by approximately $24.7 million. As at December 31, 2007, working capital was a $3.3 million deficiency compared to a working capital deficiency of $36.4 million at December 31, 2006. This was achieved as a result of many factors including the proceeds received from the Trust's May 31, 2007 equity offering, proceeds received from seven property dispositions, maintaining reasonable distributions compared to funds flow from operations for the year and capital expenditure requirements in the period and continued execution of the Trust's hedging program. Net debt includes the net working capital deficiency before short-term commodity contract assets and liabilities and short-term future income tax assets. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and long-term future income taxes.

On May 31, 2007, the Trust completed its offering, including an over-allotment option, for an aggregate of 9,430,000 trust units for gross proceeds of $57.5 million. The net proceeds of $54.4 million, after deducting unit issue costs, was used to pay down debt.

The current credit facility consists of a $15 million demand operating facility provided by one Canadian bank and a $175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution and one institutional lender. The revolving period on the revolving term credit facility ends on June 29, 2008, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on March 31, 2008. Further details of the credit facilities are disclosed in note 8 of the consolidated financial statements. As at December 31, 2007, there is approximately $22 million undrawn under these lending facilities.

The Trust does not hold any non-bank Asset-Backed Commercial Paper investments.

On June 15, 2006 the Trust completed a bought deal public offering of 86,250 7.5% convertible unsecured subordinated debentures at a price of $1,000 per debenture for aggregate gross proceeds of $86,250,000.

The debentures have a face value of $1,000 per debenture and a maturity date of June 30, 2011. The debentures bear interest at an annual rate of 7.50% payable semi-annually on June 30 and December 31 in each year commencing December 31, 2006. The debentures are convertible at anytime at the option of the holders into trust units of the Trust at a conversion price of $16.00 per trust unit. The Trust will have the right to redeem all or a portion of the debentures at a price of $1,050 per debenture after June 30, 2009 and on or before June 30, 2010 and at a price of $1,025 per debenture after June 30, 2010 and before the maturity date. Upon maturity or redemption of the debentures, the Trust may, subject to notice and regulatory approval, pay the outstanding principal and premium (if any) on the debentures in cash or through the issue of additional trust units at 95% of the weighted average trading price of the trust units.

As at February 22, 2008, the Trust had outstanding a total of 5,388,498 incentive units exercisable at an average exercise price of $8.62 per unit, 382,075 exchangeable shares (convertible, as at February 22, 2008 into an aggregate of 341,151 trust units, subject to further adjustments based on distributions made on trust units), $86.25 million principal amount of debentures convertible into trust units (at a conversion price of $16.00 per trust unit) and 79,222,715 trust units.

As announced, True intends to divest of its Saskatchewan assets as part of a new strategic direction for the Trust. Further to this announcement, True intends to divest its oil and natural gas assets in Saskatchewan including Kerrobert's SAGD project, and properties at Smiley, Coleville, Dodsland and Mantario. December 2007 average production from the Saskatchewan assets was approximately 5,600 boe/d, weighted 62% to oil (97% heavy oil, 3% light oil). The assets include 18.8 mmboe of reserves and approximately 250,000 net acres of land. True anticipates significant proceeds from the disposition of its Saskatchewan properties in a time of historically high oil prices and the current favorable royalty regime in Saskatchewan. It is anticipated that any proceeds from the disposition of the Trust's Saskatchewan assets, currently anticipated to close at the end of the first quarter of 2008, will be utilized to eliminate True's bank indebtedness and to provide additional financial resources to develop its Alberta light oil and natural gas plays.

Commitments

As at December 31, 2007, the Trust had committed to drill a total of 2 wells in Alberta with varying commitment dates up to end of the third quarter of 2008 pursuant to various farm-in agreements with oil and gas companies. True expects to satisfy these various drilling commitments at an estimated cost for True's interest of approximately $2.8 million.

The Trust has further committed to various corporate sponsorships extending to June 2011 at an estimated combined cost of up to $332,000.

Off-Balance Sheet Arrangements

The Trust has certain lease agreements, of which the office space leases are reflected in the table below, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2007.

The Trust is committed to payments under operating leases for office space as follows:

($000s) **Year**	**Gross Amount**	**Expected Recoveries**	**Net amount**
2008	$ 1,685	$ 297	$ 1,388
2009	1,893	297	1,596
2010	2,118	297	1,821
2011	2,161	-	2,161
2012	2,190	-	2,190

Business Prospects and 2008 Outlook

Since its formation in September 2000, True Energy Inc. has experienced significant growth in its production and land base. The Trust continues to develop its core assets and conduct some exploration programs utilizing its large inventory of geological prospects. In addition, the Trust will continue to explore potential acquisition opportunities. Currently, the Trust's producing properties are located in Saskatchewan, Alberta and British Columbia.

Following the results of the Special and Annual Meeting held on March 30, 2007, True remains a trust. Therefore, the focus will continue to be maintaining sufficient cash flow to provide a balance between unitholder distributions and funding of the Trust's capital program.

Advancement of the Kerrobert SAGD project continues. During the first quarter of 2008, True has increased steam rates to the 4 new steam injectors to near maximum levels. Wellhead injection pressures have uniformly increased indicating a re-pressurization of the reservoir. Further evidence of re-pressurization has been seen through the consistent increase of wellbore fluid levels and downhole pump inlet pressures. Production well temperatures have remained at near initial reservoir levels indicating even heating is underway and that no random, premature, breakthrough has occurred – a positive indicator of overall project conformance. Based on the recovery responses of the original 1996 pilot project, estimated oil rate increases on the current project should occur 4 to 6 months after start-up. As we approach the midpoint of the 4 to 6 month timing range it is clear there will not be an "early" response, however all technical parameters continue to point to a very positive project.

Field production estimates for the first quarter of 2008 are expected to average approximately 13,200 boe/d. Field production was adversely impacted by the extreme weather experienced in January and February of 2008. In addition, an unplanned third party plant outage impacted production in west central Alberta for February 2008. Work is underway to deal with a well servicing and equipment repair backlog.

True anticipates the US$/Cdn.$ exchange rate to average 1.00 through the 2008 year.

The Trust continues to maintain a large undeveloped land base of approximately 800,100 (537,800 net) acres and has identified a multi-year drilling inventory of over 375 net locations.

Gas prices continue to show volatility with uncertainty regarding weather and its effect on natural gas demand and storage and global factors including LNG shipments to North America. Given the natural gas price outlook, coming into the winter drilling season, True plans to reduce its first quarter 2008 winter drilling activity compared to the first quarter of 2007. True's first quarter 2008 capital program will not exceed $10 million which compares to a front end loaded 2007 capital program of approximately $50 million in first quarter 2007. True will continue to take a balanced approach to the priority use of cash flow between level of distributions and size of its 2008 capital program. Given the nature of True's lands and their inherent advantage of year round access, True will spread its 2008 capital program more evenly through the full year of 2008 to take advantage of reduced service costs during non-peak times. True will focus on increasing its farm-out activity in non-core areas. If the 2008 outlook for commodity prices improves, True would plan to increase its capital spending in third and fourth quarters of 2008. Additionally, any proceeds from the expected closing of True's proposed Saskatchewan asset divestiture, currently anticipated to close at the end of the first quarter of 2008, are intended to be used to pay down debt related to True's existing bank facility and fund an expanded 2008 capital program of $60 million. True's 2008 capital program, post-asset disposition, is anticipated to focus on operated core properties in West Central and Northern Alberta.

Financial Reporting Update

Capital disclosures

The CICA issued a new accounting standard, Section 1535 "Capital Disclosures", which requires the disclosure of both qualitative and quantitative information that provides users of financial statements with information to evaluate the entity's objective, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

Financial instruments

Two new accounting standards were issued by the CICA, Section 3862 "Financial Instruments – Disclosures", and Section 3863 "Financial Instruments – Presentation". These sections will replace Section 3861 "Financial Instruments – Disclosure and Presentation" once adopted. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

International Financial Reporting Standards ("IFRS")

In September 2007, the Accounting Standards Board ("AcSB") issued a bulletin relating to the transition to IFRS from Canadian GAAP and based on work undertaken to date, no significant impediments to adopting IFRS by the proposed transition date have been identified. True is monitoring industry discussion regarding the replacement of the CICA's Accounting Guideline 16 with IFRS 6, which is expected to have major implications for True's current full cost accounting policies. In February 2008, the AcSB confirmed the transition date for adopting IFRS will be January 1, 2011.

Business Risks and Uncertainties

True’s production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies.

True is subject to the various types of business risks and uncertainties including:

- Finding and developing oil and natural gas reserves at economic costs;
- Production of oil and natural gas in commercial quantities; and
- Marketability of oil and natural gas produced.

In order to reduce exploration risk, the Trust strives to employ highly qualified and motivated professional employees with a demonstrated ability to generate quality proprietary geological and geophysical prospects. To help maximize drilling success, True combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate risk prospects with some exposure to select high-risk with high-reward opportunities. True also explores in areas where the Trust has significant drilling experience.

The Trust mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems managed by qualified personnel. In addition, True seeks to maintain operational control of the majority of its prospects.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, True conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Trust maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government regulations. True may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management subject to controls established by the Board.

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 federal, provincial and local laws and regulations. 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 liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. The Federal government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

In Alberta, the reduction emission guidelines outlined the Climate Change and Emissions Management Amendment Act (the “Act”) came into effect July 1, 2007. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12 per cent. Industries have three options to choose from in order to meet the reduction requirements outlined in the Act, and these are: (a) by making improvement to operations that result in reductions; (b) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (c) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION which includes the Regulatory Framework for Air Emissions. This Action Plan covers not-only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Trust and its operations and financial condition.

On October 25, 2007, the Alberta Government announced its intent to increase royalty rates commencing on January 1, 2009. As of December 31, 2007, the province had not introduced the enabling legislation nor had they provided enough clarity on a number of issues for the Trust’s independent reserves evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), to provide a precise calculation of the net reserves and NPV under the New Royalty Framework (“NRF”). However, GLJ did provide analysis of the proposed royalty regime, based on a high and low sensitivity to the NRF utilizing the Consultants' Consensus Methodology recommended by the Society of Petroleum Engineers, Calgary Chapter (the "Consensus Methodology"). Based on currently available public information, the net present value of future net revenue of proved and probable reserves based on the high scenario at a 10% discount rate using the Consultants’ Average Forecast Prices would be $8.9 million or 1.5 percent higher and $1.9 million or 0.33% percent higher based on the NRF for the low scenario, in each case, as compared to the existing royalty rules. The proposed royalty changes are very sensitive to production rate and natural gas prices. The majority of True’s current Alberta wells are in the 500m to 1,000m depth range and typically produce at lower rates. The overall impact of the new Alberta royalty regime, as currently announced, is mitigated by the Trust’s current Saskatchewan properties and the lower shallow gas Alberta natural gas rate royalty production in True’s Alberta conventional oil and gas production portfolio. The New Alberta Royalty Framework will impact future drilling decisions in order for the Trust to maintain acceptable rates of return on its capital deployed. The Alberta Government has stated that they are reviewing with industry the proposed royalty changes to ensure that there are no unintended consequences resulting from the royalty changes. It is not known at this time whether any further revisions to the proposals will be made nor what their impact may be.

True is continuing to assess the impact on its ongoing Alberta operations. While the Trust cannot determine the full potential impact of these changes to the royalty rate on its operations at this time, it is anticipated that the impact will not be material to True given True’s production in Alberta being primarily in shallow natural gas wells. True’s proposed divestiture of its Saskatchewan assets will impact True’s weighting of production in Alberta, subject to the New Royalty Framework.

Critical Accounting Estimates

The reader is advised that the critical accounting estimates, policies, and practices as described in the Trust's Management's Discussion and Analysis continue to be critical in determining True's financial results.

The reader is cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. The following discussion outlines accounting policies and practices that are critical to determining True's financial results.

The Trust uses the full cost method of accounting for oil and gas properties. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves using forecast pricing. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. Estimated reserves are also utilized by True's bank in determining credit facilities. Reserves affect net income through depletion and the ceiling test calculation. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the financial results and financial condition.

The discounted, expected future cost of statutory, contractual or legal obligations to retire long-lived assets are recorded as an Asset Retirement Obligation ("ARO") liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases over time to its future amount through accretion charges to earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

In following the liability method of accounting for income taxes, related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings.

The Trust is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Trust's favor, the Trust does not currently believe that the outcome of adverse decisions in any pending or threatened proceeding related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position or results of operations.

With the above risks and uncertainties the reader is cautioned that future events and results may vary substantially from that which True currently foresees.

Legal, Environmental Remediation and Other Contingent Matters

The Trust reviews legal, environmental remediation and other contingent matters to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Trust's management monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by the circumstances.

Controls and Procedures

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to the Trust, including its consolidated subsidiaries, is made known to the Trust's Chief Executive Officer and Chief Financial Officer by others within those entities, particularly during the period in which the annual and interim filings are being prepared. True's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that True's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information relating to True, including its consolidated subsidiaries, is made known to them by others within those entities, particularly during the period in which the annual filings are being prepared.

Internal Controls over Financial Reporting

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 to provide reasonable assurance regarding the reliability of the Trust’s financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP.

The Trust’s Chief Executive Officer and Chief Financial Officer are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust’s most recent interim period that has materially affected, or is reasonably likely to materially affect, the Trust’s internal control over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during the three months ended December 31, 2007, that has materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

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.

Standardized Distributable Cash

The Canadian Securities Administrators recently revised and re-issued National Policy 41-201 “Income Trusts and Other Indirect Offerings”, which includes disclosures regarding distributable cash for Income Trusts. Further, the Canadian Institute of Chartered Accountants (“CICA”) issued the Interpretive Release “Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure” (the “Release”) in July 2007, which is required for the third quarter of 2007 forward. In the new guidance, sustainability concepts are discussed and standardized distributable cash is defined as cash flow from operating activities less adjustments for productive capacity maintenance, long-term unfunded contractual obligations and the effect of any foreseeable financing matters, related to debt covenants, which could impair True’s ability to pay distributions or maintain productive capacity. This Management Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA’s Release and NP 41-201.

($000s, except per unit amounts and percentages)	Years ended December 31, 2007	2006
Net loss	(24,267)	(233,564)
Cash flow from operating activities	82,206	126,800
Productive capacity maintenance (1)	(86,341)	(98,690)
Standardized distributable cash	(4,135)	28,110
Proceeds on sale of property, plant and equipment	31,808	24,514
Corporate and property acquisition and other capital expenditures	(2,561)	(17,322)
Net proceeds from issue of trust units	54,375	-
Proceeds from issue of convertible debentures, net of issue costs	-	82,261
Repurchase of trust units under normal course issuer bid	(1,658)	-
Funding from DRIP	-	42,608
Bank borrowings (debt repayment) and working capital changes and other	(4,378)	(35,816)
Cash Distributions declared	73,451	124,355
Accumulated distributions, beginning of period	141,716	17,361
Accumulated distributions, end of period	215,167	141,716
Standardized distributable cash per unit - basic	$(0.05)	$0.60
Standardized distributable cash per unit - diluted	$(0.05)	$0.60
Standardized distributable cash payout ratio (2)	N/A	4.4
Distributions declared per unit for outstanding units in the year	$0.96	$2.64
Accumulated distributions per unit, beginning of year	3.12	0.48
Accumulated distributions per unit, end of year	$4.08	$3.12
Excess (shortfall) of net income over cash distributions declared	(97,718)	(357,919)
Excess of cash flow from operating activities over cash distributions declared	8,755	2,445

(1) Please refer to the discussion of productive capacity maintenance below
(2) Represents cash distributions declared divided by standardized distributable cash

True strives to fund both distributions and maintenance capital primarily from funds flow from operations. True's 2007 capital budget was initially set at approximately 40% to 50% of annual funds flow. Property dispositions, equity issues or additional borrowings may be required from time to time to fund a portion of the distributions and/or capital expenditures to maintain or increase productive capacity may be required based on forecast levels of cash flow, capital efficiency and debt levels.

Productive capacity is the amount of capital funds required in a period for an enterprise to maintain its ability to generate future cash flow from operating activities at a constant level. As commodity prices can be volatile and short-term variations in production levels are often experienced in the oil and gas industry, True defines production capacity as production on a barrel of oil equivalent basis. A quantifiable measure for these short-term variations is not objectively determinable or verifiable due to various factors including the inability to distinguish natural production declines from the effect of production additions resulting from capital and optimization programs, and the effect of temporary production interruptions. As a result, the adjustment for productive capacity maintenance in True's calculation of standardized distributable cash is True's capital expenditures excluding the cost of any asset acquisition, corporate asset acquisitions or proceeds of any asset disposition. True believes that its capital programs based on 40% to 50% of forecasted funds flow including its current view of True's assets and opportunities and

True's outlook for commodity prices and industry conditions in the medium term, should be sufficient to maintain True's productive capacity in the medium term. True sets its hurdle rates for evaluating potential development and optimization projects according to these parameters. Due to the risks inherent in the oil and natural gas industry, particularly True's exploration and development activities and inherent variations in commodity prices, there can be no assurance that capital programs, whether limited to excess of cash flow over distributions or not, will be sufficient to maintain or increase True's production levels or cash flow from operating activities. True's capital expenditures and production can be impacted by the timing of the capital program and spring break up associated with certain operating areas of its properties. As True strives to maintain sufficient credit facilities and appropriate levels of bank debt, this seasonality is not expected to influence True's distribution policies.

True's calculation of standardized distributable cash has no adjustment for long-term unfunded contractual obligations. True's only long-term unfunded contractual obligation at this time is for asset retirement obligations. True's abandonment obligations are being funded on an annual basis with cash flow from operating activities. Cash flow from operating actitivies, used in our standardized distributable cash calculation, includes a deduction for abandonment expenditures incurred in the year. True currently has no financing restrictions on distributions arising from compliance with its debt covenants. True regularly monitors its current forecast debt levels to ensure debt covenants are not exceeded.

Distributions typically exceed net income as a result of non-cash items such as unit-based compensation, depletion, depreciation and accretion, unrealized loss (gain) on commodity contracts, and future income tax expense (recovery). These non-cash items generally result in a reduction to net income, with no impact to cash flow from operating activities. Therefore, distributions will exceed net income in most periods. In the event distributions exceed cash flow from operating activities and the requirements of True's capital program, the shortfall will typically be funded by a combination of available bank facilities, equity or debt issues, or the sale proceeds from non-core assets.

The board of directors and management regularly review the level of distributions. The board considers a number of factors, including expectations of future current commodity prices, hedge positions, production volumes, capital expenditure requirements, market conditions, the availability of debt and equity capital and other factors. As a result of the volatility in commodity prices, changes in production levels and capital expenditure requirements, there can be no certainty that True will be able to maintain current levels of distributions and distributions can and may fluctuate in the future.

($000s, except ratios)	To December 31, 2007
Cumulative distributable cash from operations [(1)]	24,298
Proceeds on sale of property, plant and equipment	56,322
Corporate and property acquisitions and other capital expenditures	(19,883)
Net proceeds from issue of trust units	54,375
Proceeds from issue of convertible debentures, net of issue costs	82,261
Repurchase of trust units under normal course issuer bid	(1,658)
Funding from DRIP	42,909
Bank borrowings (debt repayment) and working capital changes and other	(23,457)
Cumulative cash distributions declared [(1)]	215,167
Standardized distributable cash payout ratio [(2)]	8.85

(1) Subsequent to the November 2, 2005 reverse takeover of TKE Energy Trust
(2) Represents cumulative distributions declared divided by cumulative standardized distributable cash

Sensitivity Analysis

The table below shows sensitivities to funds flow as a result of product price and operational changes. This is based on actual 2007 prices received for the fourth quarter of 2007 and average production volumes of 14,937 boe/d during that period, as well as the same level of debt outstanding at December 31, 2007. Diluted weighted average trust units is based upon the fourth quarter of 2007. These sensitivities are approximations only, and not necessarily valid under other significantly different production levels or product mixes. Hedging activities can significantly affect these sensitivities. Changes in any of these parameters will affect cash flow as shown in the table below:

Sensitivity Analysis	Funds Flow from Operations (annualized) ($000s)	Funds Flow from Operations Per Diluted Unit ($)
Change of US $1/bbl WTI	1,500	0.02
Change of $0.10/ mcf	1,600	0.02
Change of US $0.01 Cdn/ US exchange rate	800	0.01
Change in prime of 1%	1,700	0.02

Selected Quarterly Consolidated Information

The following table sets forth selected consolidated financial information of the Trust for the eight most recently completed quarters at the end of 2007.

2007 – Quarter ended (unaudited) ($000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	71,196	74,991	50,547	61,756
Funds flow from operations(1)	29,988	34,192	17,478	19,514
Funds flow from operations per unit(1)				
Basic	$0.43	$0.47	$0.22	$0.25
Diluted	$0.42	$0.45	$0.22	$0.25
Net income (loss)	(8,571)	1,741	(17,003)	(434)
Net income (loss) per unit				
Basic	$(0.12)	$0.02	$(0.21)	$(0.01)
Diluted	$(0.12)	$0.02	$(0.21)	$(0.01)
Net capital expenditures (cash)	27,915	6,739	7,612	14,828
Distributions declared	16,866	18,376	19,132	19,077
Distributions per unit	$0.24	$0.24	$0.24	$0.24

2006 – Quarter ended (unaudited) ($000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	46,396	43,004	54,263	77,250
Funds flow from operations(1)	18,995	16,386	23,225	31,785
Funds flow from operations per unit(1)				
Basic	$0.52	$0.44	$0.52	$0.45
Diluted	$0.52	$0.42	$0.50	$0.44
Net income (loss)	3,259	12,243	1,652	(250,718)
Net income (loss) per unit				
Basic	$0.09	$0.43	$0.04	$(3.58)
Diluted	$0.09	$0.42	$0.04	$(3.58)
Net capital expenditures (cash)	22,561	(7,080)	46,095	29,922
Distributions declared	26,150	27,771	36,846	33,588
Distributions per unit	$0.72	$0.72	$0.72	$0.48

(1) *refer to "Non-GAAP Measures" in respect of the term "funds flow from operations" and "funds flow from operations per unit".*

The quarterly results as presented for 2006 and 2007 varied significantly for two main reasons: 1) the timing of acquisitions 2006 and 2) changes in commodity prices over those periods.

True completed the acquisitions of Shellbridge and Prairie Schooner on June 23, 2006 and September 22, 2006, respectively. True's revenue, net income, and funds flow from operations in 2006 and 2007 has reflected its production base after considering the timing of the above noted acquisitions, the results of ongoing drilling activities, and the timing of plant turnarounds and other operational challenges, as well as the changes in commodity prices, primarily that for natural gas. Beginning in 2005 and continuing into the first quarter of 2006, natural gas prices were gradually increasing; from second and third quarters of 2006, natural gas prices were on the decline; from the fourth quarter of 2006 through to the second quarter of 2007, natural gas prices were increasing; and after a decline in natural gas prices for the third quarter of 2007, natural gas prices for the fourth quarter were again on the rise. The increase or decrease in natural gas prices over these periods resulted in a corresponding increase or decrease in the Trust's petroleum and natural gas revenue, net income and funds flow from operations in the respective periods. Variations in the prices received for crude oil, condensate and NGLs during these periods also has contributed to the fluctuations in the Trust's revenue, net income and funds flow from operations in the respective periods. Certain adjustments to royalties and production expenses were recorded in 2007 for amounts related to pre-2007 as discussed earlier in those respective sections.

Net income also reflects an increase in DD&A rates since primarily since the November 2005 reverse takeover of TKE Energy Trust offset by future tax recoveries beginning in the same period. The increase in the Trust's DD&A rate for 2006 was due to an increase in its depletable base as a result of the acquisitions and further capital spending. Future tax recoveries recognized since December 2005 result from additional interest deductions associated with True's new Trust structure as well as reductions in rates for both federal and provincial taxes which were enacted during 2006 and 2007. Net income for the fourth quarter of 2006 is also reflective of a ceiling test write-down of $110.0 million and a goodwill impairment charge of $169.8 million.

Selected Annual Information

Years ended December 31, ($000s, except per unit amounts)	2007	2006	2005
Revenues before royalties and hedging	258,490	220,913	161,670
Funds flow from operations[1]	101,172	90,391	87,137
Funds flow from operations per unit[1]			
Basic	$1.33	$1.91	$3.53
Diluted	$1.33	$1.87	$3.47
Net income (loss)	(24,267)	(233,564)	13,890
Net income (loss) per unit			
Basic	$(0.32)	$(4.95)	$0.56
Diluted	$(0.32)	$(4.95)	$0.55
Net capital expenditures (cash)	57,094	91,498	115,920
Total assets	880,252	1,016,658	731,129
Total net debt [2]	251,163	275,816	111,129
Long-term financial liabilities			
Obligations under capital lease	-	-	54
Capital taxes payable	-	-	1,700
Future income taxes	67,366	123,861	146,729
Asset retirement obligations	28,373	26,605	10,457
Exchangeable shares of Subsidiary	3,922	4,153	9,709
Production (boe/d)	16,139	13,861	8,672
Distributions declared	73,451	124,355	17,361
Distributions per unit [3]	$0.96	$2.64	$0.48

(1) *refer to "Non-GAAP Measures" in respect of the term "funds flow from operations" and "funds flow from operations per unit".*
(2) *Net debt includes the net working capital deficiency before short-term commodity contract assets and liabilities and short-term future income tax assets. Total net debt also includes the liability component of convertible debentures and excludes asset retirement obligations and the future income tax liability.*
(3) *restated for changes in accounting policies and to reflect the consolidation of units effective November 2, 2005.*

TRUE ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
As at December 31

($000s)	**2007**	**2006**
ASSETS		
Current assets		
Accounts receivable	$ 48,522	$ 73,199
Deposits and prepaid expenses	6,096	7,928
Capital taxes recoverable	626	-
Commodity contract asset (note 20)	1,061	-
Future income taxes (note 15)	3,116	
	59,421	81,127
Property, plant and equipment (note 6)	820,831	931,979
Deferred financing charges (note 9)	-	3,552
Total assets	$ 880,252	$ 1,016,658
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 52,188	$ 107,431
Distribution payable to unitholders	6,337	8,433
Capital taxes payable	-	1,513
Current portion of obligations under capital lease	-	111
Commodity contract liability (note 20)	11,404	-
	69,929	117,488
Long-term debt (note 8)	168,475	157,904
Convertible debentures (note 9)	79,407	81,551
Asset retirement obligations (note 10)	28,373	26,605
Future income taxes (note 15)	67,366	123,861
Total liabilities	413,550	507,409
NON-CONTROLLING INTEREST		
Exchangeable shares of subsidiary (note 11)	3,922	4,153
UNITHOLDERS' EQUITY		
Unitholders' capital (note 12)	925,573	876,904
Equity component of convertible debentures (note 9)	5,119	5,119
Contributed surplus (note 13)	19,454	12,818
Deficit	(487,366)	(389,745)
Total unitholders' equity	462,780	505,096
Total liabilities and unitholders' equity	$ 880,252	$ 1,016,658

COMMITMENTS (note 19)

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
For the years ended December 31

($000s)	**2007**	**2006**
REVENUES		
Petroleum and natural gas sales	$ 258,490	$ 220,913
Royalties	(47,004)	(51,816)
Gain (loss) on commodity contracts (note 20)	(3,852)	2,639
	207,634	171,736
EXPENSES		
Production	68,282	46,685
Transportation	7,938	6,517
General and administrative	18,186	14,896
Interest and financing charges	18,108	10,665
Unit-based compensation (notes 12 and 13)	2,001	6,597
Depletion, depreciation and accretion	171,484	138,875
Write-down of petroleum and natural gas properties (note 6)	-	110,000
Goodwill impairment (note 7)	-	169,768
Special meeting costs (note 16)	3,805	-
	289,804	504,003
LOSS BEFORE TAXES	(82,170)	(332,267)
TAXES (note 15)		
Capital taxes	2,039	3,245
Future income tax recovery	(59,847)	(101,145)
	(57,808)	(97,900)
NET LOSS BEFORE NON-CONTROLLING INTEREST	(24,362)	(234,367)
Non-controlling interest (note 11)	(95)	(803)
NET LOSS	(24,267)	(233,564)
Net changes in cash flow hedges (net of tax of $1.8 million)	(3,749)	-
COMPREHENSIVE LOSS	$ (28,016)	$ (233,564)
Net loss per trust unit		
Basic	$ (0.32)	$ (4.95)
Diluted	$ (0.32)	$ (4.95)

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
For the years ended December 31

($000s)	**2007**	**2006**
UNITHOLDERS' CAPITAL		
Balance, beginning of year	$ 876,904	$ 418,968
Issued for cash (net of issue costs of $3.1 million)	54,375	-
Issued to acquire Prairie Schooner (net of issue costs of $1.6 million)	-	341,089
Issued to acquire Shellbridge (net of issue costs of $0.6 million	-	67,669
Units issued pursuant to DRIP	-	42,608
Issued to acquire property interest	-	1,817
Repurchased under normal course issuer bid	(5,842)	-
Exchangeable shares converted	136	4,753
Balance, end of year	925,573	876,904
EQUITY COMPONENT OF CONVERTIBLE DEBENTURES		
Balance, beginning of year	5,119	-
Conversion feature on convertible debentures issued	-	5,119
Balance, end of year	5,119	5,119
CONTRIBUTED SURPLUS		
Balance, beginning of year	12,818	5,127
Unit-based compensation expense (note 13)	4,249	7,691
Reversal of prior year unit-based compensation expense for forfeitures of unvested incentive units	(1,797)	-
Adjustment for repurchase of units under normal course issuer bid	4,184	-
Balance, end of year	19,454	12,818
DEFICIT		
Balance, beginning of year	(389,745)	(31,826)
Net loss	(24,267)	(233,564)
Impact of changes in accounting policy for financial instruments on January 1, 2007 (net of tax of $0.05 million) (note 3)	97	-
Distributions declared	(73,451)	(124,355)
Balance, end of year	(487,366)	(389,745)
ACCUMULATED OTHER COMPREHENSIVE INCOME		
Balance, beginning of year	-	-
Impact of new cash flow hedge accounting standards on January 1, 2007 (net of tax of $1.8 million) (note 3)	3,749	-
Reclassification to earnings of net hedging gains on commodity contracts (net of tax of $1.8 million)	(3,749)	-
Balance, end of year	-	-
TOTAL UNITHOLDERS' EQUITY	$ 462,780	$ 505,096

See accompanying notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31

($000s)	**2007**	**2006**
Cash provided by (used in):		
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$ (24,267)	$ (233,564)
Items not involving cash:		
Non-controlling interest (note 11)	(95)	(803)
Depletion, depreciation and accretion	171,484	138,875
Write-down of petroleum and natural gas properties (note 6)	-	110,000
Goodwill impairment (note 7)	-	169,768
Unit-based compensation (notes 12 and 13)	2,001	6,597
Unrealized loss (gain) on commodity contracts (note 20)	10,343	-
Amortization of deferred financing charges (note 9)	-	437
Accretion on convertible debentures (note 9)	1,553	420
Future income taxes (recovery) (note 15)	(59,847)	(101,145)
Capital taxes	-	(194)
	101,172	90,391
Asset retirement costs incurred	(835)	(516)
Change in non-cash working capital (note 14)	(18,131)	36,925
	82,206	126,800
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES		
Increase in bank debt	11,591	19,166
Obligations under capital lease	(111)	(201)
Issuance of convertible debentures	-	86,250
Deferred financing charges	-	(3,989)
Issue of trust units for cash	57,523	-
Unit issue costs	(3,148)	(2,410)
Repurchase of trust units under normal course issuer bid	(1,658)	-
Distributions declared (net of DRIP)	(73,451)	(81,747)
	(9,254)	17,069
Change in non-cash working capital (note 14)	(2,060)	(101)
	(11,314)	16,968
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES		
Additions to property, plant and equipment	(88,902)	(116,012)
Proceeds on sale of property, plant and equipment	31,808	24,514
Corporate transaction costs	-	(2,083)
	(57,094)	(93,581)
Change in non-cash working capital (note 14)	(13,798)	(55,405)
	(70,892)	(148,986)
Cash acquired on corporate acquisition (note 5b)	-	5,218
Change in cash	-	-
Cash, beginning of period	-	-
Cash, end of period	$ -	$ -

See accompanying notes to the consolidated financial statements.

1. STRUCTURE OF THE TRUST

True Energy Trust ("True" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta. Pursuant to a Plan of Arrangement (the "TKE Arrangement") that became effective on November 2, 2005, True Energy Inc. and TKE Energy Trust ("TKE") entered into a business combination whereby True Energy Inc. acquired TKE in a reverse takeover, thus creating True Energy Trust and a publicly listed exploration focused company, Vero Energy Inc.

The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and net profits interests in oil and natural gas properties. The business of the Trust is carried on by True Energy Inc. and its wholly owned subsidiary True Energy Peru S.A.C. The Trust owns, directly and indirectly, 100% of the common shares, (excluding the exchangeable shares – see note 10) of True Energy Inc. and True Energy Peru S.A.C. The activities of True Energy Inc. are financed through interest bearing notes from the Trust and third party debt as described in the notes to the financial statements.

Pursuant to the terms of a Net Profit Interest Agreement (the "NPI Agreement"), the Trust is entitled to a payment from True Energy Inc. each month equal to the amount by which 99% of the gross proceeds from the sale of production exceed certain deductible expenditures (as defined). Under the terms of the NPI Agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of True Energy Inc. as applicable.

The Trust will make distributions to the Unitholders in amounts equal to all or any part of the net income of the Trust earned from interest income on the notes and from the income generated under the NPI Agreement, and from any dividends paid on the common shares of True Energy Inc., less any expenses of the Trust including interest on the convertible debentures.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Trust have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas, and crude oil reserves and future costs required to develop those reserves. Actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment and reasonable limits of materiality and within the framework of the significant policies summarized below.

a. Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to the "Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

b. Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title to the products transfers to the purchasers based on volumes delivered and contracted delivery points and prices.

c. Joint Interests

A significant portion of the Trust's exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Trust's proportionate interest in such activities.

d. Petroleum and Natural Gas Properties

The Trust follows the full cost method of accounting for petroleum and natural gas operations whereby all costs related to the exploration and development of petroleum and natural gas reserves are capitalized. These costs include land acquisition costs, geological and geophysical expenses, the costs of drilling both productive and non-productive wells, directly related overhead and estimated abandonment costs. Proceeds from the disposal of properties are deducted from the full cost pool without recognition of a gain or loss unless such a sale would significantly alter the rate of depletion and depreciation.

e. Depletion and Depreciation

Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved reserves as determined by independent engineers and calculated in accordance with National Instrument 51-101. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced. The costs of acquiring and evaluating unproved properties are excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Depreciation of office furniture and equipment is provided for on a 20% declining balance basis.

f. Ceiling Test

The Trust applies a two-stage ceiling test on the aggregate carrying value of its capitalized costs, which may be amortized against revenues of future periods. The first stage of this process is to ensure that such costs do not exceed the undiscounted future cash flows from production of proved reserves. Undiscounted future cash flows are calculated based on management's best estimate of forward indexed prices applied to estimated future production of proved reserves plus the carrying cost of undeveloped properties, less estimated future operating costs, royalties, future development costs and abandonment costs. When the carrying amount of a cost centre is not recoverable, the second stage of the process will determine the impairment whereby the cost centre would be written down to its fair value. The second stage requires the calculation of discounted future cash flows from proved plus probable reserves plus the carrying cost of undeveloped properties net of any impairment allowance. The fair value of proved and probable reserves is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows.

The cost of undeveloped properties is excluded from the impairment test described above and subject to a separate impairment test.

g. Goodwill

Goodwill is recognized on acquisitions when the total purchase price exceeds the fair value of the net identifiable assets of the acquired company. The carrying value of goodwill is assessed for impairment annually at year-end, or more frequently if events occur that could result in an impairment. Impairment is verified by comparing the carrying amount of the goodwill for the reporting entity to the excess of the Trust's fair value of its publicly traded trust units over the related book value. If the fair value of the Trust's equity is less than the book value, impairment is measured by allocating the fair value of the Trust to its identifiable assets and liabilities at their fair values. The excess of this allocation represents the fair value of goodwill. The excess of the book value of goodwill over this implied fair value is then recognized through the statement of income as an impairment. Impairment is charged to income in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized.

h. Asset Retirement Obligations

The Trust recognizes a liability for the future retirement obligations associated with the Trust's property, plant, and equipment. The fair value of the asset retirement obligation is recorded on a discounted basis. This amount is also capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the Trust settles the obligation.

i. Unit-based Compensation Plan

The Trust accounts for its Trust Unit Incentive Plan issued to employees and the Board of Directors using the fair value method. The fair value of each trust unit incentive is estimated on the date of the grant using the Black-Scholes options pricing model and charged to earnings over the vesting period with a corresponding increase to contributed surplus.

j. Income Taxes

Income taxes are recorded using the liability method of tax allocation. Future income tax assets and liabilities are determined based on “temporary differences” and are measured using the current, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders.

k. Exchangeable Shares of Subsidiary

The exchangeable shares can be traded privately, thereby allowing holders of the exchangeable shares to dispose of them without having to exchange them for trust units, and consequently, they must be classified as a non-controlling interest outside of Unitholders' Equity.

l. Financial Instruments

All financial instruments, including all derivatives, are recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available for sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in income. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to income when derecognized or impaired.

The Trust continues to utilize financial derivatives and non-financial derivatives, such as commodity sales contracts requiring physical delivery, to manage the price risk attributable to anticipated sale of petroleum and natural gas production. The Trust does not enter into derivative financial instruments for trading or speculative purposes.

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

The Trust has elected to account for its commodity sales and purchase contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as derivatives.

Subsequent changes in fair value of derivatives that are not designated or do not qualify for hedge accounting or normal purchase, sale or usage contracts are recognized in net income as incurred. For derivatives that are designated and qualify for cash flow hedge accounting at inception or the date of adoption, the effective portion of the change in fair value is recognized in other comprehensive income as incurred with the remaining portion of the change in fair value recognized in net income as incurred in the same financial statement caption as the hedged transaction. Net derivative gains (losses) in accumulated other comprehensive income are reclassified to net income in the same financial statement caption and future periods as the hedged transactions affect net income.

m. Basic and Diluted per Trust Unit Calculations

Basic per trust unit amounts are calculated using the weighted average number of trust units outstanding during the period. The Trust uses the treasury stock method to determine the dilutive effect of trust incentive units. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted per unit amounts. The Trust uses the "if-converted" method to determine the dilutive effect of exchangeable shares and convertible debentures.

n. Measurement Uncertainty

The amounts recorded for depletion, depreciation and accretion expense, asset retirement obligations and amounts used in the impairment tests for goodwill and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value 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 material.

o. Financial Presentation and Disclosure

Certain prior period comparative figures have been restated to conform to the current year's presentation.

3. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, True adopted accounting standards related to the new financial instruments accounting framework, which encompasses three new Canadian Institute of Chartered Accountant ("CICA") Handbook Sections: 3855 "Financial Instruments – Recognition and Measurement", 3865 "Hedges", and 1530 "Comprehensive Income". Handbook Section 3251 "Equity" was also effective for True on January 1, 2007. In accordance with these standards, prior period financial statements have not been restated.

At January 1, 2007, the following adjustments were made to the balance sheet to adopt the new standards:

Increase (decrease) ($000s)		**At January 1, 2007**
Commodity contract asset		$ 8,905
Deposits and prepaid expenses		
Deferred commodity contract premiums	(3,310)	
Prepaid interest	(1,020)	
		(4,330)
Deferred financing charges		(3,552)
Long-term debt		(1,020)
Convertible debentures		(3,697)
Future income tax liability		1,894
Deficit, net of income taxes of $0.05 million		(97)
Accumulated other comprehensive income		
Cash flow hedges, net of income taxes of $1.8 million		3,749

a. Financial instruments – recognition and measurement

This new standard requires all financial instruments within its scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available for sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in income. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to income when derecognized or impaired. Changes to the measurement of existing financial assets and liabilities at the date of adoption were adjusted to either opening retained earnings or opening accumulated other comprehensive income as noted above.

b. Derivatives

The Trust continues to utilize financial derivatives and non-financial derivatives, such as commodity sales contracts requiring physical delivery, to manage the price risk attributable to anticipated sale of petroleum and natural gas production. Refer to note 20 to for additional disclosure on the Trust's risk management objectives and policies.

The Trust has elected to account for its commodity sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as derivatives. Prior to adoption of the new standards, physical receipt and delivery contracts did not fall within the scope of the definition of a financial instrument and were also accounted for as executory contracts.

Subsequent changes in fair value of derivatives that are not designated or do not qualify for hedge accounting or normal purchase, sale or usage contracts are recognized in net income as incurred. For derivatives that are designated and qualify for cash flow hedge accounting at inception or the date of adoption, the effective portion of the change in fair value is recognized in other comprehensive income as incurred with the remaining portion of the change in fair value recognized in net income as incurred in the same financial statement caption as the hedged transaction. Net derivative gains (losses) in accumulated other comprehensive income are reclassified to net income in the same financial statement caption and future periods as the hedged transactions affect net income. Prior to adoption, financial derivatives which were designated and qualified for cash flow hedge accounting were recognized on an accrual basis.

Prior to January 1, 2007, the Trust applied hedge accounting, under the former Accounting Guideline 13 standard, to its financial derivatives, being commodity price risk management contracts. On January 1, 2007, the Trust discontinued hedge accounting for all existing financial derivatives. As a result, the mark-to-market gain on these financial derivatives, net of existing unamortized deferred commodity contract premiums and the tax effect thereon was included in accumulated other comprehensive income as of January 1, 2007. These net derivative gains in accumulated other comprehensive income at January 1, 2007 were reclassified to income throughout 2007 as the original hedged transactions affect net earnings. From January 1, 2007 forward, the changes in fair value of such derivatives will be recognized in net income when incurred.

c. Embedded derivatives

On adoption, the Trust elected to recognize, as separate assets and liabilities, only those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

d. Other comprehensive income

The new standards require a statement of comprehensive income, which is comprised of net income and other comprehensive income which, for the Trust, relates to changes in gains or losses on derivatives that were previously designated as cash flow hedges. The Company has combined this new statement with the statement of income.

e. Effective interest rate method

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the life of the resulting financial instrument. Prior to January 1, 2007, transaction costs were recorded as deferred charges and recognized in net earnings on a straight-line basis over the life of the financial instrument. On adoption, transaction costs are recognized as if the effective interest rate method had always been applied whereby the amount recognized varies over the life of the financial instrument based on principal outstanding. For the Trust, this adoption required adjustments to prepaid expenses and long-term debt as disclosed in note 8 and to deferred financing costs and the debt component of convertible debentures as disclosed in note 9.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

a. Capital disclosures

The CICA issued a new accounting standard, Section 1535 “Capital Disclosures”, which requires the disclosure of both qualitative and quantitative information that provides users of financial statements with information to evaluate the entity’s objective, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

b. Financial instruments

Two new accounting standards were issued by the CICA, Section 3862 “Financial Instruments – Disclosures”, and Section 3863 “Financial Instruments - Presentation. These sections will replace Section 3861 “Financial Instruments – Disclosure and Presentation” once adopted. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity’s financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

5. ACQUISITIONS

a. Acquisition of Prairie Schooner Petroleum Ltd.

Effective September 22, 2006, the Trust's wholly owned subsidiary, True Energy Inc. ("True Energy"), entered into a business combination with Prairie Schooner Petroleum Ltd. ("Prairie Schooner") whereby True Energy acquired all of the issued and outstanding shares of Prairie Schooner pursuant to a plan of arrangement. The previous shareholders of Prairie Schooner received 1.22 trust units of the Trust for each outstanding Prairie Schooner share and outstanding options were exchanged for options ("replacement options") to purchase trust units adjusted for the exchange ratio and exercisable for ten business days following completion of the transaction (the "Transaction"). An aggregate of 25,759,563 trust units were issued pursuant to the Transaction (including on exercise of the replacement options). Concurrent with the business combination, True Energy and Prairie Schooner amalgamated on September 22, 2006 and continued as True Energy. The value of the transaction, based upon the adjusted weighted average trading price for trust units of the Trust for the five days prior to the transaction announcement on July 26, 2006, of $13.31, was $344.4 million (including $1.6 million in transaction costs). The transaction was accounted for using the purchase method.

The purchase price allocation resulted in an excess purchase price over the fair value of net identifiable assets acquired of approximately $71.6 million, which was reflected as goodwill. The accounts include the results of Prairie Schooner from September 22, 2006, the date Prairie Schooner shares were exchanged for trust units of the Trust. The purchase equation was adjusted at December 31, 2006 to reflect certain underaccruals for operating and capital expenditures relating to the period prior to September 22, 2006. As a result, accounts payable was increased by $3.6 million, the future tax liability was reduced by $1.9 million and goodwill was increased by $1.7 million. The purchase price equation is as follows:

($000's)	
Cost of acquisition:	
Trust units issued	$ 342,870
True transaction costs	1,563
	$ 344,433
Allocated at estimated fair values:	
Accounts receivable	$ 32,295
Deposits and prepaid expenses	1,075
Property, plant and equipment	435,346
Goodwill	71,601
Bank debt	(67,373)
Accounts payable and accrued liabilities	(42,636)
Future income taxes	(73,467)
Asset retirement obligations	(12,408)
	$ 344,433

b. Acquisition of Shellbridge Oil & Gas, Inc.

Effective June 23, 2006, the Trust's wholly owned subsidiary, True Oil & Gas Ltd. ("True Oil & Gas"), entered into a business combination with Shellbridge Oil & Gas, Inc. ("Shellbridge") whereby True Oil & Gas acquired all of the issued and outstanding shares of Shellbridge pursuant to a plan of arrangement. The previous shareholders of Shellbridge received 0.14 trust units of the Trust for each outstanding Shellbridge share (the "Transaction"), resulting in the issuance of 4,389,366 trust units. Concurrent with the business combination, True Oil & Gas and Shellbridge amalgamated on June 23, 2006 and continued as True Oil & Gas. The value of the transaction, based upon the adjusted weighted average trading price for True Energy Trust units for the five days prior to the transaction announcement on April 11, 2006, of $15.56, was $68.8

million (including $0.5 million in transaction costs). The transaction was accounted for using the purchase method.

The purchase price allocation resulted in an excess purchase price over the fair value of net identifiable assets acquired of approximately $24.0 million, which was reflected as goodwill. The accounts include the results of Shellbridge effective June 23, 2006, the date Shellbridge shares were exchanged for trust units of the Trust.

The purchase price equation is as follows:

($000's)	
Cost of acquisition:	
Trust units issued	$ 68,299
True transaction costs	520
	$ 68,819
Allocated at estimated fair values:	
Cash	$ 5,218
Accounts receivable	10,005
Deposits and prepaid expenses	161
Property, plant and equipment	47,529
Goodwill	24,017
Accounts payable and accrued liabilities	(13,485)
Future income taxes	(3,330)
Asset retirement obligations	(1,296)
	$ 68,819

6. PROPERTY, PLANT AND EQUIPMENT

($000s)

December 31, 2007	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas properties	$ 1,371,069	$ 552,899	$ 818,170
Office furniture and equipment	4,092	1,431	2,661
	$ 1,375,161	**$ 554,330**	**$ 820,831**
December 31, 2006			
Petroleum and natural gas properties	$ 1,314,374	$ 384,110	$ 930,264
Office furniture and equipment	2,588	873	1,715
	$ 1,316,962	**$ 384,983**	**$ 931,979**

The Trust has included $56.6 million (2006 - $63.0 million) for future development costs and excluded $nil million (2006 - $99.2 million) for undeveloped properties, $37.8 million (2006 - $49.3 million) for undeveloped land and $47.6 million (2006 - $49.9 million) for estimated salvage from the depletion calculation during the year ended December 31, 2007.

For the year ended December 31, 2007, the Trust capitalized $3.9 million (2006 - $2.6 million) of general and administrative expenses and $0.7 million (2006 - $1.1 million), including the future tax effect thereon of $0.2 million, of unit-based compensation expense directly related to exploration and development activities.

The Trust performed a ceiling test calculation at December 31, 2007 resulting in undiscounted cash flows from proved reserves plus the carrying cost less impairment allowance of unproved properties not exceeding the carrying value of oil and gas assets. Consequently, True performed stage two of the ceiling test assessing whether discounted future cash flows from the production of proved plus probable reserves plus the carrying cost less impairment allowance of unproved properties exceeded the carrying value of its petroleum and natural gas properties. No impairment in oil and gas assets was identified for 2007.

In 2006, as a result of performing this test, a ceiling test impairment loss of $110.0 million was recorded as a write-down of petroleum and natural gas properties in the consolidated statements of operations and was included in accumulated depletion.

The prices used in the ceiling test evaluation of the Trust's crude oil and natural gas reserves at December 31, 2007 were based on the following benchmark price forecasts adjusted for quality and transportation differentials:

Year	Hardisty Heavy Crude Oil ($/bbl)	Edmonton Light Sweet Crude Oil ($/bbl)	AECO Natural Gas ($/mmbtu)
2008	$ 54.66	$ 89.42	$ 6.48
2009	52.41	85.78	7.18
2010	50.42	82.82	7.35
2011	49.02	80.29	7.35
2012	48.68	79.74	7.36
2013	48.87	79.52	7.48
2014	49.86	80.56	7.67
2015	50.89	81.65	7.87
2016	51.93	82.72	8.07
2017	52.98	84.41	8.27
2018	54.03	86.09	8.45
2019	55.10	87.81	8.64
Percentage increase each year after 2019	2.0%	2.0%	2.0%

On December 17, 2007, the Trust announced its intention to divest of its Saskatchewan portfolio of assets as part of a new strategic direction for the Trust. Scotia Waterous Inc. has been selected to act as True's exclusive advisor in this process. Bids were received on March 4, 2008 and are subject to review and acceptance by the Trust.

7. GOODWILL

($000s)	**2007**	**2006**
Balance, beginning of year	$ -	$ 71,970
Prairie Schooner acquisition (note 3a)	-	71,601
Shellbridge acquisition (note 3b)	-	24,017
TKE acquisition (note 3c)	-	2,180
Goodwill impairment recognized	-	(169,768)
Balance, end of year	$ -	$ -

The Trust reviewed the valuation of goodwill as of December 31, 2006 based upon the latest available data. Based upon this review, an impairment of goodwill of $169.8 million was recorded as a non-cash charge to income as of December 31, 2006.

8. LONG-TERM DEBT

The Trust has a $15 million demand operating facility provided by one Canadian bank and $175 million extendible revolving term credit facility syndicated by two Canadian chartered banks, a U.S. bank, a Canadian financial institution and one institutional lender. Amounts borrowed under the credit facility bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rates, LIBOR rates, plus between 0% and 1.95%, depending on the types of borrowings and the Trust's debt to cash flow ratio. Security is provided by a $400 million debenture containing a first ranking security interest on all of the Trust's assets. The credit facility is secured against all the assets of True Energy Inc., the Trust and all material subsidiaries. True has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances. A standby fee is charged on between 0.125% and 0.400% on the undrawn portion of the facility, depending on the Trust's debt to cash flow ratio.

As a consequence of adopting new financial instruments standards effective January 1, 2007 as described in note 3, the Trust has made certain adjustments to the presentation of prepaid interest. Previously, this amount was included in deposits and prepaid expenses, however, under the new standard effective January 1, 2007 this amount, being $1.0 million at December 31, 2007, is now netted against long-term debt and amortized on the effective interest basis.

As at December 31, 2007, there was $10.5 million outstanding under the operating facility and $158 million outstanding under the revolving term credit facility. As at December 31, 2007, there is approximately $21.5 million not drawn under the facility.

The borrowing base was renewed effective August 31, 2007 and is currently scheduled for renewal on or before March 31, 2008.

The revolving period on the new revolving term credit facility ends on June 28, 2008, unless extended for a further 364 day period. Should the facilities not be renewed they convert to 366 day non-revolving term facilities on the renewal date. Payment will not be required under the revolving term facility for more than 365 days from the balance sheet date and as at December 31, 2007 there is sufficient availability under the revolving term credit facility to also cover the operating facility and, as such, the entire credit facility has been classified as long-term.

9. CONVERTIBLE DEBENTURES

On June 15, 2006, the Trust completed a public offering of 86,250 7.5% convertible unsecured subordinated debentures at a price of $1,000 per debenture for aggregate gross proceeds of $86,250,000.

The convertible debentures have a face value of $1,000 per debenture and a maturity date of June 30, 2011. The convertible debentures bear interest at an annual rate of 7.50% payable semi-annually on June 30 and December 31 in each year commencing December 31, 2006. The debentures are convertible at anytime at the option of the holders into trust units of the Trust at a conversion price of $16.00 per Trust unit. The Trust will have the right to redeem all or a portion of the debentures at a price of $1,050 per debenture after June 30, 2009 and on or before June 30, 2010 and at a price of $1,025 per debenture after June 30, 2010 and before the maturity date. Upon maturity or redemption of the debentures, the Trust may, subject to notice and regulatory approval, pay the outstanding principal and premium (if any) on the debentures in cash or through the issue of additional Trust units at 95% of a weighted average trading price of the Trust units.

The debentures were initially recorded at the fair value of the obligation without the conversion feature. This fair value to make future payments of principal and interest was initially determined to be $81.1 million. The difference between the principal amount of $86.3 million and the fair value of the obligation is $5.1 million and has been recorded in unitholders' equity as the fair value of the conversion feature of the debentures. Issue costs of $4.0 million were classified as deferred financing charges, and prior to January 1, 2007, were amortized on a straight-line basis over the term of the debentures. As a consequence of adopting new financial instruments standards effective January 1, 2007 as described in note 3, the Trust made certain adjustments to deferred financing charges and the debt component of convertible debentures as noted in the tables below. The debt component of the convertible debentures will accrete up to the principal balance at maturity. The accretion and the interest paid are expensed as interest and financing charges in the consolidated statement of operations.

The following table shows the convertible debenture activities for the years ended December 31, 2007 and 2006:

Convertible debentures

	Number of Debentures	Debt Component *($000s)*	Equity Component *($000s)*
Issued on June 15, 2006	86,250	$ 81,131	$ 5,119
Accretion	-	420	-
Balance, December 31, 2006	86,250	81,551	5,119
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	-	(3,697)	-
Accretion	-	1,553	-
Balance, December 31, 2007	**86,250**	**$ 79,407**	**$ 5,119**

The following table shows the deferred financing charges activities for the years ended December 31, 2007 and 2006:

Deferred financing charges

($000s)	**2007**	**2006**
Balance, beginning of year	$ 3,552	$ -
Costs incurred for convertible debenture offering	-	3,989
Less amortization in the year	-	(437)
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	(3,552)	-
Balance, end of year	**$ -**	**$ 3,552**

10. 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 is approximately $75.2 million which will be incurred between 2008 and 2053. A credit-adjusted risk-free rate of 8 percent and an inflation rate of 2 percent were used to calculate the fair value of the asset retirement obligation.

($000s)	**2007**	**2006**
Asset retirement obligation, beginning of year	$ 26,605	$ 10,457
Liabilities acquired through corporate acquisitions	-	13,704
Liabilities incurred on development activities	433	1,210
Changes in prior period estimates	960	1,326
Liabilities released on dispositions	(927)	(641)
Liabilities settled during the year	(835)	(516)
Accretion expense	2,137	1,065
Asset retirement obligation, end of year	**$ 28,373**	**$ 26,605**

11. EXCHANGEABLE SHARES OF SUBSIDIARY / NON-CONTROLLING INTEREST

Authorized:

Unlimited number of exchangeable shares, issuable in series of which the first series in an unlimited number is designated for Series A exchangeable shares

	2007		2006	
	Number	**Amount *($000s)***	**Number**	**Amount *($000s)***
Balance, beginning of year	403,536	$ 4,153	788,558	$ 9,709
Non-controlling interest expense (recovery)	-	(95)	-	(803)
Exchanged for trust units	(13,260)	(136)	(385,022)	(4,753)
Balance, end of year	**390,276**	**$ 3,922**	**403,536**	**$ 4,153**

The Series A exchangeable shares are non-voting (but holders are entitled to equivalent voting rights in the Trust) and can be converted, at the option of the holder into trust units at any time. If the number of exchangeable shares outstanding is less than 180,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchangeable ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions; however cash distributions will increase the exchange ratio.

As at December 31, 2007, the exchange ratio was 0.8604 (2006 – 0.71107).

Retraction of Exchangeable Shares

Exchangeable shares may be redeemed at any time by delivering the share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On January 15, 2010, the exchangeable shares will be redeemed by the Trust unless the Board of Directors of True Energy Inc. elects to extend the redemption period. The exchangeable shares generally will be redeemed issuing units for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

12. UNITHOLDERS' CAPITAL

a. Trust Units

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 net 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 are redeemable at any time at the lesser of 90% of the market price (as determined in accordance with the Trust Indenture) and the closing price of the trust units on the date tendered for redemption to a maximum, unless waived, of $250,000 per calendar month in which case the redemption price is payable by distributing notes of the Trust's subsidiary or notes of the Trust.

	2007		2006	
	Number	Amount ($000s)	Number	Amount ($000s)
Balance, beginning of year	70,275,703	$ 876,904	36,176,196	$ 418,968
Issued for cash (net of issue costs of $3.1 million)	9,430,000	54,375	-	-
Issued to acquire Prairie Schooner (net of issue costs of $1.8 million)	-	-	25,759,563	341,089
Issued to acquire Shellbridge (net of issue costs of $0.6 million)	-	-	4,389,366	67,669
Units issued pursuant to DRIP	-	-	3,574,185	42,608
Issued to acquire property interest	-	-	145,358	1,817
Repurchased under normal course issuer bid	(500,000)	(5,842)	-	-
Exchangeable shares converted	10,343	136	231,035	4,753
Balance, end of year	**79,216,046**	**$ 925,573**	**70,275,703**	**$ 876,904**

In August 2007, the Trust announced approval of its normal course issuer bid ("NCIB") program to repurchase up to 7.8 million of its outstanding trust units during the period August 28, 2007 through to August 27, 2008, subject to certain conditions. Starting in the fourth quarter and through the end of 2007, 500,000 units were repurchased at a total price of $1.7 million. The excess of the carrying amount of the units purchased over the purchase price of $4.2 million was recorded as an increase to contributed surplus.

b. Trust Unit Incentive Plan

The Trust has a trust unit incentive plan where the Trust may grant trust unit incentive rights to its directors, officers and employees. Under this plan, the exercise price of each trust unit incentive right initially equals the market price of the Company's stock on the date of grant. The maximum term of an incentive right is five years.

The grant price per Incentive Right ("Grant Price") shall be equal to the per Trust Unit closing price on the trading day immediately preceding the date of grant, unless otherwise permitted. Under the terms of the Incentive Plan, the exercise price of each Incentive Right is initially equal to the Grant Price and thereafter is reduced pursuant to a formula. This formula provides that the exercise price of each Incentive Right is reduced by any decreases in the daily closing price on the Toronto Stock Exchange of the Trust Units that is in excess of a 2.5% return on the Trust's consolidated net fixed assets (the "Hurdle Rate"); provided however, that such decrease in the exercise price will not exceed the amount by which the Trust Unit distributions exceed the Hurdle Rate. Effective June 1, 2006, the Trust amended its Hurdle Rate to 0% per quarter. In no case may the exercise price be less than $0.001 per Trust Unit and a participant may elect to have the exercise price equal the Grant Price. Incentive Rights are non-transferable or assignable except in accordance with the Incentive Plan and the holding of Incentive Rights shall not entitle a holder to any rights as a Unitholder of True Energy Trust.

Unit rights, entitling the holder to purchase units from the Trust, have been granted to directors, officers, employees and service providers of the Trust. Effective May 1, 2006, one third of the initial grant of trust unit incentives vest on each of the first, second, and third anniversary from the date of grant.

The following tables summarize information regarding trust unit incentive rights for the years ended December 31, 2007 and 2006.

Unit Rights Continuity

	Weighted Average Exercise Price[a]	Number
Balance, December 31, 2005	$ 17.94	3,159,000
Granted	$ 12.67	3,022,500
Forfeited	$ 14.66	(751,669)
Balance, December 31, 2006	$ 14.18	5,429,831
Granted	$ 5.06	3,181,500
Forfeited	$ 12.50	(2,679,334)
Balance, December 31, 2007	**$ 9.18**	**5,931,997**

Unit Rights Outstanding, December 31, 2007

		Outstanding			Exercisable	
Exercise Price Before Price Reductions	Exercise Price Net of Reductions	**At Dec. 31, 2007**	Weighted Average Exercise Price Net of Price Reductions	Weighted Average Remaining Contractual Life	**At Dec. 31, 2007**	Exercise Price Net of Price Reductions
$ 2.92 - $ 6.70	$ 2.92 - $ 6.13	2,745,000	$ 4.56	4.6	-	N/A
$10.58 - $12.53	$ 9.27 - $11.12	914,998	$ 9.56	3.8	361,648	$ 9.54
$13.74 - $14.83	$11.75 - $12.92	527,166	$ 12.11	3.5	213,497	$ 12.17
$15.92 - $16.70	$13.37 - $14.28	92,500	$ 13.74	3.3	48,334	$ 13.80
$18.25 - $20.98	$15.27 - $18.22	1,652,333	$ 15.46	2.9	1,620,665	$ 15.41
$ 2.92 - $20.98	**$ 2.92 - $18.22**	**5,931,997**	**$ 9.18**	**3.9**	**2,244,144**	**$ 14.12**

Units Rights Outstanding, December 31, 2006

		Outstanding			Exercisable	
Exercise Price Before Price Reductions	Exercise Price Net of Reductions	**At Dec. 31, 2006**	Weighted Average Exercise Price Net of Price Reductions	Weighted Average Remaining Contractual Life	**At Dec. 31, 2006**	Exercise Price Net of Price Reductions
$10.58 - $12.53	$10.15 - $12.00	1,539,000	$ 10.40	4.7	-	N/A
$13.74 - $14.83	$12.63 - $13.80	681,000	$ 13.05	4.5	-	N/A
$15.92 - $16.70	$14.41 - $15.16	227,500	$ 14.61	4.3	29,166	14.93
$18.25 - $20.98	$16.15 - $19.10	2,982,331	$ 16.36	3.9	1,919,888	16.27
$10.58 - $20.98	$10.30 - $19.10	5,429,831	$ 14.18	4.2	1,949,054	16.25

[a] Exercise prices reflect grant prices less reduction in exercise prices.

c. Employee Trust Unit Savings Plan

Effective October 1, 2006, the Trust introduced an employee trust unit savings plan for the benefit of all employees. Under the savings plan, employees may elect to contribute up to 10 percent of their salary and contributions are used to fund the acquisition of trust units. The Trust matches employee contributions at a rate of $1.00 for each $1.00 contributed. Trust units are purchased in the open market by the plan administrator, an investment firm, on behalf of the participants in the plan. For the year ended December 31, 2007, the Trust matched $0.5 million (2006 - $0.1 million) under the plan.

13. CONTRIBUTED SURPLUS

($000s)	2007	2006
Balance, beginning of year	$ 12,818	$ 5,127
Unit-based compensation expense	4,249	7,691
Reversal of prior year unit-based compensation expense for forfeitures of unvested incentive units	(1,797)	-
Adjustment for repurchase of units under NCIB (note 12)	4,184	-
Balance, end of year	**$ 19,454**	**$12,818**

Unit-based Compensation Expense

During the year ended December 31, 2007, the Trust granted 3,181,500 (2006 – 3,022,500) unit incentive rights to employees and directors. During the year ended December 31, 2007, the Trust recorded unit-based compensation of $4.2 million, of which $0.5 million was capitalized to property, plant and equipment.

The fair values of all incentive rights granted are estimated on the date of grant using the Black-Scholes option-pricing model.

The weighted average fair market value of incentive rights granted during the years ended December 31, 2007 and 2006 and the assumptions used in their determination are as noted below.

	2007	2006
Assumptions:		
Risk free interest rate (%)	4	4
Expected life (years)	5	5
Expected volatility (%)	24-26	24
Results:		
Weighted average fair value of each incentive right granted	$ 1.85	$ 4.27

14. SUPPLEMENTAL CASH FLOW INFORMATION

Cash Interest and Taxes Paid

($000s)	2007	2006
Cash paid:		
Interest	$ 16,566	$ 10,598
Taxes (net of refunds)	$ 4,378	$ 4,476

Change in Non-cash Working Capital

($000s)	2007	2006
Changes in non-cash working capital items:		
Accounts receivable	$ 24,677	$ 25,633
Deposits and prepaid expenses	812	(4,887)
Accounts payable and accrued liabilities	(55,243)	(37,449)
Capital taxes recoverable/payable	(2,139)	(1,634)
Distribution payable to unitholders	(2,096)	(244)
	$ (33,989)	$ (18,581)
Changes related to operating activities	$ (18,131)	$ 36,925
Changes related to financing activities	(2,060)	(101)
Changes related to investing activities	(13,798)	(55,405)
	$ (33,989)	$ (18,581)

15. INCOME TAXES

The Trust is a mutual fund trust as defined under the Income Tax Act (Canada). All taxable income earned by the Trust has been allocated to unitholders and such allocations are deducted for income tax purposes.

In June 2007, the government legislation implementing the new tax (the "SIFT tax") on publicly traded income trust and limited partnerships (Bill C-52) received third reading in the House of Commons and Royal Assent. For existing income trusts and limited partnerships, the SIFT tax will be effective in 2011 unless certain rules related to "undue expansion" are not adhered to. As such, the Trust would not be subject to the new measures until the 2011 taxation year provided the Trust continues to meet certain requirements.

As a result of the SIFT tax enactment, the Trust recorded a future income tax recovery of $1.2 million to reflect current temporary differences between the book and tax basis of assets and liabilities expected to be remaining in the Trust in 2011. In accordance with generally accepted accounting principles, prior to the enactment, the Trust's temporary differences were not recorded as future income taxes. As at December 31, 2007, the total "temporary difference" (tax basis exceeds accounting basis) in the Trust is $8.1 million. As at December 31, 2007, the Trust's subsidiaries have a tax basis of approximately $510 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately $34.8 million that expire in years through 2027. In addition, the Trust itself has approximately $21 million of tax basis.

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate of 32.98% (2006: 35.63%) to earnings before income taxes. This difference results from the following items:

	Years ended December 31,	
($000s)	**2007**	**2006**
Expected income tax expense (recovery)	$ (27,099)	$ (118,645)
Distributions deducted for tax purposes	(22,857)	(33,757)
Goodwill impairment	-	60,620
Impact of SIFT legislation	(1,165)	-
Crown royalties and charges	-	5,032
Resource allowance	-	(4,292)
Unit based compensation expense	660	2,356
Change in enacted tax rates	(9,444)	(11,548)
Other	58	(911)
Future income tax expense (recovery)	**$ (59,847)**	$ (101,145)

The components of the net future income tax liability at December 31 are as follows:

($000s)	**2007**	**2006**
Future income tax liabilities:		
Petroleum and natural gas properties	$ (87,564)	$ (120,203)
Partnership deferrals	-	(16,374)
Other	(565)	(565)
Future income tax assets:		
Future site restoration/asset retirement obligation	7,682	7,899
Share issue costs	1,345	2,207
Non-capital losses	10,502	1,856
Attributed Canadian Royalty Income	1,209	1,209
Commodity contract asset/liability	3,116	-
Other	25	110
Net future income tax liability	**$ (64,250)**	**$ (123,861)**

16. SPECIAL MEETING COSTS

On January 15, 2007, the Trust announced its proposal to convert into an intermediate exploration and production company (the "Reorganization"). Pursuant to the Reorganization, it was contemplated that holders of trust units of the Trust would receive an equal number of common shares of a newly formed corporation that will hold the assets previously held directly or indirectly by the Trust. The exchangeable shares were also to be exchanged for common shares based on the conversion ratio thereof. The Reorganization was subject to all required regulatory approvals and securityholder approval by at least 66 2/3% of the votes cast by unitholders of the Trust and holders of the exchangeable shares. At the Special and Annual Meeting held on March 30, 2007, the special resolution related to the Reorganization was not approved. As a result, the Reorganization was not completed.

The Trust incurred $3.8 million in costs for legal, financial advisory, accounting, unitholder solicitation services, printing, mailing and other expenses that are included as special meeting costs within the statement of income for the year ended December 31, 2007.

17. PER TRUST UNIT AMOUNTS

	Years ended December 31,	
	2007	**2006**
Basic trust units outstanding	79,216,046	70,275,703
Dilutive effect of:		
Trust unit incentive rights outstanding	5,931,997	5,429,831
Units issuable for exchangeable shares	335,793	286,942
Units issuable for convertible debentures	5,390,625	5,390,625
Diluted trust units outstanding	90,874,461	81,383,101
Weighted average trust units outstanding	75,792,488	47,217,258
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures [(1)]	-	-
Diluted weighted average trust units outstanding	75,792,488	47,217,258

(1) A total of 335,793 (2006: 286,942) exchangeable shares, 5,931,997 (2006: 5,429,831) trust incentive units and 5,390,625 (2006: 5,390,625) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the year ended December 31, 2007 as they were not dilutive.

18. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2007, the Trust paid $1.2 million (2006: $1.2 million) for legal services provided by a firm in which a current director and corporate secretary is a partner. These payments were made in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

19. COMMITMENTS

As at December 31, 2007, the Trust had committed to drill a total of 2 wells in Alberta with varying commitment dates up to the end of the third quarter of 2008 pursuant to various farm-in agreements with oil and gas companies. True expects to satisfy these various drilling commitments at an estimated cost for True's interest of approximately $2.8 million.

The Trust has further committed to various corporate sponsorships extending to June 2011 at an estimated combined cost of up to $332,000.

The Trust is committed to payments under operating leases for office space as follows:

($000s) Year	Gross Amount	Expected Recoveries	Net amount
2008	$ 1,685	$ 297	$ 1,388
2009	1,893	297	1,596
2010	2,118	297	1,821
2011	2,161	-	2,161
2012	2,190	-	2,190

20. FINANCIAL INSTRUMENTS

a. Credit Risk

A substantial portion of the Trust's accounts receivable are with customers and joint interest partners in the petroleum and natural gas industry and are subject to normal industry credit risks. The Trust sells substantially all of its production to eleven primary purchasers under normal industry sale and payment terms. Purchasers of the Trust's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

b. Fair Value of Financial Instruments

At December 31, 2007, the following table provides the carrying amount and fair value of the Company's financial instruments:

($000s)		Carrying amount	Fair value
Commodity contract asset		$ 1,061	$ 1,061
Commodity contract liability		11,404	11,404
Long-term debt		168,475	168,475
Convertible debentures			
Debt component	79,407		
Equity component	5,119		
		84,526	79,350

The carrying values of accounts receivable, deposits and prepaid expenses, capital taxes receivable, and accounts payable and accrued liabilities approximate their fair value due to their short-term maturity.

The Trust's derivatives are exchange traded or transacted in an over-the-counter market. Where available, valuation is determined by reference to readily available public data. The carrying value of long-term debt approximates fair value due to the cost of borrowing being at a floating rate. The fair value of convertible debentures is based upon the closing market trading price as at December 31, 2007.

c. Interest Rate Risk

The Trust is exposed to interest rate risk to the extent that changes in market interest rates will impact True's bank debt that has a floating interest rate. The trust's convertible debentures have a fixed coupon interest rate of 7.5%. The Trust had no interest rate swaps or hedges at December 31, 2007.

d. Commodity Risk

The Trust has a formal risk management policy which permits management to use specified price risk management strategies for up to 50% of crude oil, natural gas and NGL production including fixed price contracts, costless collars and the purchase of floor price options and other derivative financial instruments to reduce the impact of price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to cash distributions, as well as, to ensure True realizes positive economic returns from its capital developments and acquisition activities.

As at December 31, 2007, the Trust had entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Oil collar	Oct. 1, 2007 to March 31, 2008	2,000 bbl/d	$ 65.00 US	$ 75.00 US	WTI
Oil collar	April 1, 2008 to Dec. 31, 2008	1,000 bbl/d	$ 65.00 US	$ 82.00 US	WTI
Oil collar	April 1, 2008 to Dec. 31, 2008	1,000 bbl/d	$ 65.00 US	$ 82.00 US	WTI
Natural Gas collar	Nov. 1, 2007 to March 31, 2008	5,000 GJ/day	$ 8.00 CDN	$ 9.05 CDN	AECO
Natural Gas fixed	Jan. 1, 2008 to Dec. 31, 2008	5,000 GJ/day	$ 6.65 CDN	$ 6.65 CDN	AECO
Natural Gas fixed	Jan. 1, 2008 to Dec. 31, 2008	10,551 GJ/day	$ 6.65 CDN	$ 6.65 CDN	AECO

Subsequent to December 31, 2007, the Trust has entered into additional commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural Gas fixed	April 1, 2008 to Oct. 31, 2008	5,275 GJ/day	$ 6.64 CDN	$ 6.64 CDN	AECO
Natural Gas fixed	April 1, 2008 to Oct. 31, 2008	3,500 GJ/day	$ 6.90 CDN	$ 6.90 CDN	AECO
Natural Gas fixed	Nov. 1, 2008 to Dec. 31, 2008	3,500 GJ/day	$ 7.58 CDN	$ 7.58 CDN	AECO
Natural Gas fixed	Nov. 1, 2008 to March 31, 2009	5,275 GJ/day	$ 7.61 CDN	$ 7.61 CDN	AECO
Natural Gas fixed	Jan. 1, 2009 to March 31, 2009	5,275 GJ/day	$ 7.86 CDN	$ 7.86 CDN	AECO
Natural Gas fixed	April 1, 2009 to June 30, 2009	5,275 GJ/day	$ 7.01 CDN	$ 7.01 CDN	AECO
Natural Gas fixed	April 1, 2009 to June 30, 2009	5,275 GJ/day	$ 7.015 CDN	$ 7.015 CDN	AECO

For the year ended December 31, 2007, the gain (loss) on commodity contracts was comprised of the following:

($000s)	Activity in the period	Adjustments for new standards [1]	2007 Total	2006 Total
Gain (loss) on commodity contracts				
Realized [2]	$ 9,801	$ (3,310)	$ 6,491	$ 2,639
Unrealized [3]	(19,248)	8,905	(10,343)	-
	$ (9,447)	$ 5,595	$ (3,852)	$ 2,639

(1) Refer to note 3 which describes the transitional adjustments for adoption of the accounting for the new financial instrument standards in relation to the Trust's commodity contracts.

(2) Realized gains and losses on commodity contracts represent actual cash settlements and other amounts paid under these contracts.

(3) Unrealized gains and losses on commodity contracts represent non-cash adjustments for changes in the fair value of these contracts during the period.

ADDITIONAL INFORMATION

Oil and Gas Working Interest [1] Gross Reserves

Reconciliation of Proved Reserves [2]

	Crude oil & NGL (mbbl)	**Natural gas** (mmcf)	**Equivalent units** (mboe)
December 31, 2006	11,745	116,038	31,085
Revision of previous estimates	594	7,881	1,907
Discoveries, extensions, infill drilling and improved recovery	1,061	6,419	2,131
Dispositions, net of acquisitions	(684)	(5,964)	(1,678)
Production	(1,938)	(23,526)	(5,858)
December 31, 2007	10,778	100,848	27,587
Proved plus probable reserves			
December 31, 2007	18,862	159,264	45,405
December 31, 2006	18,553	180,670	48,665

[1] "Working interest" refers to the Trust's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of the Trust. Also referred to as Company Gross under NP 51-101.

[2] Forecast prices before royalties.

True Energy Trust is a Calgary-based oil and natural gas trust. True is an open-ended, incorporated investment trust governed by the laws of the Province of Alberta. The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and net profits interests. The trust structure allows individual unitholders to participate in the cash flow of the business. Cash flow is realized from the Trust's subsidiaries' ownership of natural gas and petroleum properties and related facilities. Trust units of True trade on the Toronto Stock Exchange ("TSX") under the symbol TUI.UN. For further information, please contact:

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