



For Immediate Release
TSX: TUI.UN

TRUE ENERGY TRUST ANNOUNCES SECOND QUARTER 2007 FINANCIAL RESULTS

August 9, 2007 – (TSX: TUI.UN) True Energy Trust (“True” or the “Trust”) is pleased to announce its financial and operating results for the three and six months ended June 30, 2007. Highlights from the quarter include:

- True generated average sales volumes for the second quarter of 2007 of 17,122 boe/d as compared to 10,697 boe/d for the same period in 2006, representing a 60% increase. Sales volumes decreased 7% from first quarter 2007 volumes. In addition to the property dispositions during the first six months of 2007, third party plant turnarounds during the month of June reduced production by approximately 400 to 600 boe/d. The Trust continues to experience production declines at its Mantario heavy oil property due to various performance issues. During the second quarter, production at Mantario was approximately 1,000 boe/d less than the 2006 exit rate from the property. Production volumes from the property were approximately 1,200 boe/d as at June 30, 2007. True is proceeding with its strategies to mitigate continued impact from the property.
- Cash flow from operations* for the second quarter of 2007 was \$34.2 million on gross sales of \$75.0 million compared to cash flow from operations of \$16.4 million on gross sales of \$43.0 million for the same period in 2006. The increase in cash flow for the 2007 second quarter was primarily the result of higher production volumes as well as overall higher realized commodity prices and a more active hedging program as compared to the same period in 2006. In comparison, cash flow from operations for the first quarter of 2007 was \$30.0 million on gross sales of \$71.2 million.
- On May 31, 2007, True completed its equity offering, including an over-allotment option, for an aggregate of 9,430,000 trust units at \$6.10 per unit for gross proceeds of \$57.5 million. The net proceeds of \$54.4 million, after deducting unit issue costs, were used to pay down debt.
- An additional property disposition closed in the second quarter for net proceeds of \$9.0 million.
- True has reduced its net debt by approximately \$54.8 million for the six month period ended June 30, 2007. This was achieved as a result of many factors including the proceeds received from the Trust’s recent equity offering, proceeds received from three property dispositions, maintaining sustainable distributions compared to cash flows from operations and capital expenditure requirements in the period and continuation of the Trust’s active hedging program.
- True recently entered into two new commodity price risk management contracts: 1) an oil collar with a West Texas Intermediate (“WTI”) reference crude oil price floor of US\$65.00 per barrel and a price ceiling of US\$82.00 per barrel on 1,000 barrels per day for the second quarter of 2008 through to the fourth quarter of 2008; and 2) an AECO reference price natural gas collar with a floor price of \$8.00 per GJ and a ceiling price of \$9.05 per GJ on 5,000 GJ per day for the period of November 1, 2007 through March 31, 2008. Currently, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 25,000 GJ/d of natural gas for the third quarter 2007, 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 5,000 GJ/d of natural gas for the first quarter of 2008, and 1,000 bbls/d of crude oil for the second to fourth quarters of 2008.

* Refer to note (2) in the highlights section of the second quarter report in respect of the term “cash flow from operations”.

True’s second quarter report is presented below.

HIGHLIGHTS

	Three months ended June 30		Six months ended June 30	
	2007	2006	2007	2006
FINANCIAL <i>(unaudited)</i>				
<i>(CDN\$000s except unit and per unit amounts)</i>				
Revenue (before royalties and hedging ⁽¹⁾)	74,991	43,004	146,187	89,400
Cash flow from operations ⁽²⁾	34,192	16,386	64,180	35,381
Per basic trust unit	\$0.47	\$0.43	\$0.89	\$0.97
Per diluted trust unit ⁽³⁾	\$0.45	\$0.42	\$0.88	\$0.95
Net income (loss)	1,741	12,243	(6,830)	15,502
Per basic trust unit	\$0.02	\$0.33	\$(0.10)	\$0.43
Per diluted trust unit ⁽³⁾	\$0.02	\$0.33	\$(0.09)	\$0.42
Distributions declared	18,376	27,771	35,242	53,921
Per unit	\$0.24	\$0.72	\$0.48	\$1.44
Exploration and development	15,503	17,368	61,344	39,829
Corporate and property acquisitions	649	68	1,354	192
Capital expenditures - cash	16,152	17,436	62,698	40,021
Property dispositions - cash	(9,026)	(24,514)	(27,469)	(24,514)
Corporate acquisitions and other - non-cash	311	47,321	(313)	47,956
Total capital expenditures - net	7,437	40,243	34,916	63,463
Long-term debt	142,153	21,834	142,153	21,834
Convertible debentures	78,636	81,168	78,636	81,168
Working capital deficiency	256	26,519	256	26,519
Total net debt	221,045	129,521	221,045	129,521
Total assets	941,122	759,489	941,122	759,489
Unitholders' equity	520,326	449,975	520,326	449,975
OPERATING				
Daily sales volumes				
Crude oil and NGLs	(bbls/d)	5,546	3,639	6,007
Natural gas	(mcf/d)	69,455	42,348	70,686
Total oil equivalent	(boe/d)	17,122	10,697	17,788
Average prices				
Crude oil and NGLs	(\$/bbl)	50.90	57.43	45.74
Crude oil and NGLs (including hedging ⁽¹⁾)	(\$/bbl)	49.64	56.60	46.40
Natural gas	(\$/mcf)	7.60	5.98	7.43
Natural gas (including hedging ⁽¹⁾)	(\$/mcf)	8.63	5.98	7.88
Total oil equivalent	(\$/boe)	47.33	43.23	44.96
Total oil equivalent (including hedging ⁽¹⁾)	(\$/boe)	51.08	42.95	46.99
Statistics				
Operating netback	(\$/boe)	26.79	22.20	25.53
Operating netback (including hedging ⁽¹⁾)	(\$/boe)	30.53	21.92	27.55
Production expenses	(\$/boe)	12.69	9.58	10.79
General & administrative	(\$/boe)	2.78	3.91	2.87
Royalties as a % of sales after transportation		14%	24%	17%
		24%	17%	24%

	Three months ended June 30		Six months ended June 30	
	2007	2006	2007	2006
TRUST UNITS				
Trust units outstanding	79,709,119	41,837,743	79,709,119	41,837,743
Trust unit incentive rights outstanding	6,687,499	3,552,333	6,687,499	3,552,333
Units issuable for exchangeable shares	309,216	258,445	309,216	258,445
Units issuable for convertible debentures	5,390,625	5,390,625	5,390,625	5,390,625
Diluted trust units outstanding	92,296,459	51,039,146	92,296,459	51,039,146
Diluted weighted average trust units ⁽³⁾	75,810,961	38,489,057	72,201,103	37,412,422

TRUST UNIT TRADING STATISTICS

(CDN\$, except volumes) based on intra-day trading

High	6.83	17.65	7.47	21.30
Low	5.71	12.66	4.87	12.66
Close	5.75	13.74	5.75	13.74
Average daily volume	438,393	231,034	520,700	310,462

⁽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 unaudited interim 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 in income for the period.

⁽²⁾ The highlights section contains the term "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 cash flow from operations or cash flow from operations per trust unit may not be comparable with the calculation of similar measures for other entities. Management uses cash flow from operations to analyze operating performance and leverage and considers cash 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 cash flow from operations and cash flow from operating activities can be found in the Management Discussion and Analysis ("MD&A"). Cash flow from operations per trust unit is calculated using the diluted weighted average number of trust units for the period.

⁽³⁾ In computing weighted average diluted earnings per trust unit for the three month period ended June 30, 2007 2,320,716 (2006: 1,156,88

3) trust units were added to the 73,490,245 (2006: 37,332,174) weighted average number of trust units outstanding during the period for the dilutive effect of exchangeable shares and convertible debentures. A total of 4,875,999 (2006: 3,448,203) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the three month period ended June 30, 2007 as they were not dilutive. To calculate weighted average diluted cash flow from operations for the three month period ended June 30, 2007, a total of \$2.0 million for interest accretion expense was added to the numerator and 5,390,625 trust units were added to the denominator for units issuable on conversion of convertible debentures, resulting in diluted weighted average trust units of 81,201,586 under this calculation.

In computing weighted average diluted earnings per trust unit for the six month period ended June 30, 2007 309,216 (2006: 941,528) trust units were added to the 71,891,887 (2006: 36,470,894) weighted average number of trust units outstanding during the period for the dilutive effect of exchangeable shares and convertible debentures. A total of 6,887,499 (2006: 3,435,717) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to conversion of convertible debentures were excluded from the calculation of diluted earnings per trust unit for the six month period ended June 30, 2007 as they were not dilutive. To calculate weighted average diluted cash flow from operations for the six month period ended June 30, 2007, a total of \$4.0 million for interest accretion expense was added to the numerator and 5,390,625 trust units were added to the denominator for units issuable on conversion of convertible debentures, resulting in diluted weighted average trust units of 77,591,728 under this calculation.

REPORT TO UNITHOLDERS

The second quarter of 2007 the Trust focused on improving its balance sheet, executing our disposition program, improving the working capital position and identifying the opportunities for the next 18 months from an extensive list of drilling prospects. Accomplishments for the second quarter ended June 30, 2007 include:

Distributions

In the second quarter of 2007, monthly distributions of \$0.08 per unit were declared and paid on May 15, 2007, June 15, 2007 and July 16, 2007. The Board has announced it has set a distribution policy for the third quarter of 2007 at a monthly rate of \$0.08 per unit, subject to monthly confirmation, based on current commodity prices, hedging program, production volumes and market conditions. This go-forward strategy for the distribution level is consistent with providing a balance between providing income to unitholders and funding for True's capital program required to further develop its land base.

Production

2007 second quarter sales volumes averaged 17,122 boe/d as compared to 10,697 boe/d for the same period in 2006, representing a 60% increase. For the six month period ended June 30, 2007, sales volumes averaged 17,788 boe/d as compared to 11,181 boe/d for the same period in 2006. Sales volumes in the second quarter decreased 7% from the first quarter 2007 volumes. This takes into account the impact of dispositions of certain properties at the end of March 2007 and other properties in May 2007. In addition to the dispositions, third party plant turnarounds during the month of June reduced production by approximately 400 to 600 boe/d. The Trust continues to experience production declines at its Mantario heavy oil property due to various performance issues. During the second quarter, production at Mantario was approximately 1,000 boe/d less than the 2006 exit rate from the property. Production volumes from the property were approximately 1,200 boe/d as at June 30, 2007. True is proceeding with its strategies to mitigate continued impact from the property.

During the first quarter of 2007, new Kerrobert thermal wells were drilled and facility upgrades continued throughout the second quarter. Execution of the Kerrobert steam assisted gravity drainage ("SAGD") project is on track with expected steam injection for phase one to commence at the end of the third quarter. We are forecasting that the third quarter will be negatively impacted by additional major third party plant turnarounds in West Central Alberta. Approximately 2,000 boe/d of production will be shut-in for a period during the third quarter from our Willesden Green properties. During the shut-in period the Trust will gather extensive pressure data on the tight gas reservoirs and perform a number of workovers. The remaining behind pipe production, workovers, and the Kerrobert SAGD start-up will provide visible growth prior to the end of the 2007 year. With these forecasted turnarounds and completed dispositions the Trust is anticipating 2007 annual average volumes of approximately 17,000 boe/d.

Financial

Cash flow from operations for the second quarter was \$34.2 million on gross sales of \$75.0 million compared to cash flow from operations of \$16.4 million on gross sales of \$43.0 million for the same period in 2006. The increase in cash flow for the 2007 second quarter was primarily the result of higher production volumes as well as overall higher realized commodity prices and a more active hedging program as compared to the same period in 2006.

Cash flow from operations for the six month period ended June 30, 2007 was \$64.2 million on gross sales of \$146.2 million compared to cash flow from operations of \$35.4 million on gross sales of \$89.4 million for the same period in 2007.

The net income for the 2007 second quarter was \$1.7 million compared to net income of \$12.2 million in second quarter of 2006. The net loss for the six month period ended June 30, 2007 was \$6.8 million compared to net income of \$15.5 million for the same period in 2006. This is primarily reflective of increased cash flow from operations, unrealized gains on commodity contracts in 2007, offset by a lower future tax recovery and by higher depletion, depreciation and accretion charges from recent 2006 acquisitions.

Drilling

Following the execution of True's extensive Q1 drilling program of 34 (24.0 net) wells, the main focus for the second quarter was on tie-ins and further upgrades to the Kerrobert SAGD facility. During the second quarter of 2007, True successfully drilled 1 (0.8 net) natural gas well in the Pembina area of West Central Alberta.

Dispositions

Dispositions during the second quarter of 2007 consisted of the sale of certain Peace River Arch properties, which are outside of the Trust's core areas for future development. This property sale closed on May 15, 2007 with net proceeds after adjustments of \$9.0 million that was used to pay down debt. The Trust continues to evaluate further opportunities with its divestiture program.

Subsequent to June 30, 2007, True closed the sale of two minor properties. The total net proceeds received on the sale of these properties after adjustments was \$0.8 million and was used to pay down debt.

International

The Trust along with Veraz Petroleum Ltd. ("Veraz") was successful in acquiring the right to evaluate a 2.5 million acre concession in Peru. At this stage the Trust has no financial obligation under the arrangement but holds an option to participate in the opportunity through participating in future equity issues done by Veraz to finance the project. The Board will evaluate the opportunity and decide if this is a prudent long-term opportunity for the unitholders. This proposed structure is similar to that which has been pursued by other Canadian Trusts on international ventures.

Liquidity

On May 31, 2007, the Trust completed its offering, including an over-allotment option, for an aggregate of 9,430,000 trust units at \$6.10 per unit 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.

True's net debt as at June 30, 2007 was \$221.0 million, representing \$142.2 million outstanding on the credit facility, \$78.6 million in convertible debentures (liability component) and the balance a net working capital deficiency.

The existing credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$185 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 June 30, 2007, there is approximately \$57 million undrawn under these lending facilities.

True has continued its active commodity price risk management program. True recently entered into two new commodity price risk management contracts: 1) an oil collar with a West Texas Intermediate ("WTI") reference crude oil price floor of US\$65.00 per barrel and a price ceiling of US\$82.00 per barrel on 1,000 barrels per day for the second quarter of 2008 through to the fourth quarter of 2008; and 2) an AECO reference price natural gas collar with a floor price of \$8.00 per GJ and a ceiling price of \$9.05 per GJ on 5,000 GJ per day for the period of November 1, 2007 through March 31, 2008. As of August 8, 2007, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 25,000 GJ/d of natural gas for the third quarter 2007, 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 5,000 GJ/d of natural gas for the first quarter of 2008, and 1,000 bbls/d of crude oil for the second to fourth quarters of 2008. The Trust will continue its hedging strategies focusing on maintaining sufficient cash flow to fund True's unitholder distributions and capital program.

SIFT tax enactment

In June 2007, the federal 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. This new tax will take effect in 2011 provided certain conditions continue to be met. As a result of the enactment of the SIFT tax, the Trust recorded a future income tax recovery of \$1.2 million. The SIFT tax enactment and the related future income tax recovery did not affect cash flow or distributions in the quarter and is not expected to affect our distribution policies until 2011 at the earliest. Our Board of Directors and Management continue to review the impact of this tax on our business strategy although we do not expect any changes in the short term.

Personnel Announcements

Further to our press release dated March 15, 2007, we announced a restructuring of our senior management team for May 2007. On May 14, 2007 Wayne M. Chorney joined True in the capacity of President and Chief Operating Officer, bringing with him 23 years of industry experience. On July 24, 2007, Wayne Jessee stepped down from his role as Executive Vice President to pursue other opportunities. In addition, Garth Wiggins recently resigned from the Board. On behalf of the Board, I would like to thank Mr. Wiggins and Mr. Jessee for their significant contributions to the Trust.

Paul R. Baay
Chairman & CEO
August 9, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

August 9, 2007 - 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 unaudited interim consolidated financial statements and selected notes for the three and six months ended June 30, 2007 and 2006 and the audited consolidated financial statements and Management's Discussion and Analysis for the years ended December 31, 2006 and 2005 for the Trust. This commentary is based on information available to, and is dated, August 9, 2007. 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 equivalence (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 "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 diluted cash flow from operations or cash flow from operations per unit may not be comparable with the calculation of similar measures for other entities. Management uses cash flow from operations to analyze operating performance and leverage and considers cash 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 cash flow from operations and cash flow from operating activities can be found in the management's discussion and analysis. Cash flow from operations per unit is calculated using the diluted weighted average number of units for the period.

This Management's Discussion and Analysis also contains the term "distributable cash" which is not a recognized measure under Canadian GAAP. Management uses distributable cash to refer to the determination of cash available for distribution to unitholders. True's method of calculating these measures may differ from other entities, and accordingly, may not be comparable to the measures used by other trusts or companies. 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 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 earnings 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 or wells to be tied-in, timing of and the effect of third party plant turnarounds, the effect of government announcements, proposals and legislation, plans regarding hedging, wells to be drilled, the effect of recent legislation, expected or anticipated production rates, the weighting of production between different commodities, commodity prices, exchange rates, expected levels of royalty rates, production expenses, transportation costs and other costs and expenses, distributions and taxability of distributions, 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 exhausted. 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.

Net Income (Loss) and Cash Flow from Operations

True generated cash flow from operations of \$34.2 million (\$0.45 per diluted unit) for the three months ended June 30, 2007, up 110% from the \$16.4 million (\$0.42 per diluted unit) for the second quarter of 2006. The increase in cash flow for the 2007 second quarter was the result of higher production volumes as well as higher overall realized commodity prices and a more active commodity hedging program as compared to the same period in 2006. Cash flow from operations for the six month period ended June 30, 2007 was \$64.2 million (\$0.88 per diluted unit), up 81% from the \$35.4 million (\$0.95 per diluted unit) for the same period in 2006.

The net income for the 2007 second quarter was \$1.7 million compared to net income of \$12.2 million in second quarter of 2006. The net loss for the six month period ended June 30, 2007 was \$6.8 million compared to net income of \$15.5 million for the same period in 2006. This is primarily reflective of increased cash flow from operations, unrealized gains on commodity contracts in 2007, offset by a lower future tax recovery compared to 2006 and by higher depletion, depreciation and accretion charges from the Q2 and Q3 2006 acquisitions of Shellbridge Oil & Gas, Inc. ("Shellbridge") and Prairie Schooner Petroleum Ltd. ("Prairie Schooner"), respectively.

Cash Flow From Operations and Net Income

<i>(\$000s, except per unit amounts)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Cash flow from operations	34,192	16,386	64,180	35,381
Basic (\$/unit)	0.47	0.43	0.89	0.97
Diluted (\$/unit)	0.45	0.42	0.88	0.95
Net income (loss)	1,741	12,243	(6,830)	15,502
Basic (\$/unit)	0.02	0.33	(0.10)	0.43
Diluted (\$/unit)	0.02	0.33	(0.09)	0.42

Reconciliation of Cash Flow from Operations and Distributions

Distributable cash is determined by aggregating various amounts received, including interest income on notes of subsidiaries and other interest income received or receivable, income generated under net profits interest, royalty, other permitted investments and dividends and other distributions on securities of subsidiaries, after deduction of all expenses and liabilities of the Trust. The portion of distributable cash declared payable to unitholders on any distribution date is determined on recommendation of the Board of Directors of True Energy Inc., as administrator of the Trust.

Reconciliation of Cash Flow from Operations and Distributions

(\$000s, except per unit amounts)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Cash flow from operations	34,192	16,386	64,180	35,381
Change in non-cash working capital	(29,403)	(7,523)	(19,244)	(15,909)
Cash flow from operating activities	4,789	8,863	44,936	19,472
Cash withheld to fund capital expenditures, net of disposition proceeds	(7,126)	7,078	(35,229)	(15,507)
Funding from DRIP	-	13,747	-	15,064
Net proceeds from issue of trust units	54,386	-	54,386	-
Proceeds from issue of convertible debentures, net of issue costs	-	82,227	-	82,227
Debt repayment and working capital changes	(33,673)	(84,144)	(28,851)	(47,335)
Distributions paid	18,376	27,771	35,242	53,921
Accumulated distributions, beginning of period	158,582	43,511	141,716	17,361
Accumulated distributions, end of period	176,958	71,282	176,958	71,282
Distributions per unit for outstanding units in the period	0.24	0.72	0.48	1.44
Accumulated distributions per unit, beginning of period	3.36	1.20	3.12	0.48
Accumulated distributions per unit, end of period	3.60	1.92	3.60	1.92

The Premium DistributionTM 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.

Sales Volumes

2007 second quarter sales volumes averaged 17,122 boe/d as compared to 10,697 boe/d for the same period in 2006, representing a 60% increase. For the six month period ended June 30, 2007, sales volumes averaged 17,788 boe/d as compared to 11,181 boe/d for the same period in 2007. Sales volumes in the second quarter decreased 7% from the first quarter 2007 volumes. This takes into account the impact of dispositions of certain properties at the end of March 2007 and other properties in May 2007. In addition to the dispositions, third party plant turnarounds during the month of June reduced production by approximately 400 to 600 boe/d. The Trust continues to experience production declines at its Mantario heavy oil property due to various performance issues. During the second quarter of 2007, production at Mantario was approximately 1,000 boe/d less than the 2006 exit rate from the property. Production volumes from the property were approximately 1,200 boe/d as at June 30, 2007. True is proceeding with its strategies to mitigate continued impact from the property. At the end of the second quarter, 6 wells in West Central Alberta were awaiting down-hole completion and/or completion of

production facilities. True's significant drilling activity in the first quarter of 2007 is expected to contribute to production primarily in the third and fourth quarters of 2007.

For the three month period ended June 30, 2007, the weighting towards natural gas production averaged 68% compared to 66% in the same period in 2006. For the six month period ended June 30, 2007, the weighting towards natural gas averaged 66% compared to 64% for the same period in 2006. Heavy oil sales made up 18% of total production for the second quarter of 2007 compared to 21% in the same period in 2006. In comparison, heavy oil sales made up 24% of total production in the first quarter of 2007; the decrease in heavy oil sales from Q1 to Q2 2007 is primarily due to reduced heavy oil production in the Mantario area. The September 2006 acquisition of Prairie Schooner also added significant natural gas volumes which has increased the natural gas production weighting. Currently, the Trust estimates that the weighting towards natural gas production is approximately 67%.

Sales Volumes

		Three months ended June 30,		Six months ended June 30,	
		2007	2006	2007	2006
Natural gas	(mcf/d)	69,455	42,348	70,686	42,668
Heavy oil	(bbls/d)	3,058	2,232	3,703	2,400
Light oil and condensate	(bbls/d)	1,743	1,122	1,632	1,386
NGLs	(bbls/d)	745	285	672	284
Total crude oil and NGLs	(bbls/d)	5,546	3,639	6,007	4,070
Total boe/d	(6:1)	17,122	10,697	17,788	11,181

Sales of natural gas averaged 69.4 mmcf/d for the second quarter of 2007, compared to 42.3 mmcf/d in 2006, an increase of 64%. In comparison, natural gas volumes averaged 71.9 mmcf/d for the first quarter of 2007.

Crude oil and NGL sales for the second quarter of 2007 averaged 5,546 bbls/d up 52% from average sales of 3,639 bbls/d in the same period of 2006. Most of this increase was due to greater oil volumes from the acquisition of Shellbridge in June 2006 and an increased drilling program in 2006 and 2007. In comparison, crude oil and NGL sales for the first quarter of 2007 were 6,472 bbls/d; the decrease from the first quarter of 2007 to the second quarter of 2007 is primarily due to a reduction in heavy oil volumes, primarily in the Mantario area.

Commodity Prices

Average Commodity Prices

	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Exchange rate (US\$/Cdn\$)	0.9108	0.8920	2	0.8810	0.8791	-
Natural gas:						
NYMEX (US\$/mmbtu)	7.66	6.64	15	7.41	7.23	3
Alberta spot (\$/mcf)	7.07	6.00	18	7.23	6.76	7
True's average price (\$/mcf)	7.60	5.98	27	7.43	6.94	7
True's average price (including hedging) (\$/mcf)	8.63	5.98	44	7.88	6.94	14
Crude oil:						
WTI (US\$/bbl)	65.02	70.72	(8)	61.67	67.13	(8)
Edmonton par – light oil (\$/bbl)	72.66	78.85	(7)	70.21	74.13	(5)
Bow River – medium/heavy oil (\$/bbl)	50.69	60.48	(16)	50.24	50.66	(1)
Hardisty Heavy – heavy oil (\$/bbl)	42.95	42.00	2	42.82	53.35	(20)
True's average prices (\$/bbl)						
Light crude and condensate	64.89	70.48	(8)	60.53	63.27	(4)
Light crude and condensate (including hedging)	60.89	67.80	(10)	62.97	62.18	1
NGLs	50.54	56.59	(11)	45.35	53.46	(15)
Light crude oil, condensate, and NGLs	60.59	67.66	(10)	56.10	61.60	(9)
Light crude oil, condensate and NGLs (including hedging)	57.79	65.53	(12)	57.83	60.69	(5)
Heavy crude oil	43.01	50.97	(16)	39.28	37.59	3
Total crude oil and NGLs	50.90	57.43	(11)	45.74	47.44	(4)
Total crude oil and NGLs (including hedging)	49.64	56.60	(12)	46.40	47.07	(1)

True's natural gas is primarily sold on the daily spot market. During second quarter of 2007, the Alberta Spot reference price increased by 18% compared to the same period in 2006. True's average sales price before transportation and hedging for the second quarter of 2007 averaged \$7.60/mcf for its natural gas, 27% more than the \$5.98/mcf received in 2006. In comparison, True's average sales price for natural gas averaged \$7.26/mcf for the fourth quarter of 2006. The natural gas revenues for the period reflect adjustments related to prior production periods; excluding these adjustments the average sales price for natural gas would have been approximately \$7.29/mcf for the second quarter of 2007.

For heavy crude oil, True received an average price before transportation of \$43.01/bbl during the second quarter of 2007, a decrease of 16% over 2006 prices. The Bow River reference price decreased by 16% and the Hardisty Heavy reference price increased by 2% 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. A different heavy oil property mix as compared to the prior year has resulted in True's price for the quarter being more closely aligned with the Hardisty Heavy price. In comparison, True received an average heavy oil price of \$36.64/bbl for the first quarter of 2007.

For light oil, condensate and NGLs, True recorded an average \$60.59/bbl before hedging during the second quarter of 2007, 10% lower than the average price received in 2006. During this same period, the Edmonton par price decreased by 7%. In comparison, True received an average oil price for light oil, condensate and NGLs of \$50.77/bbl in the first quarter of 2007. True's realized price increased 19% from the first quarter to the second quarter of 2007, whereas the Edmonton par price increased by 7% over the same period. The primary reason for this difference is a 30% increase in True's average price received for NGLs and higher NGL volumes experienced for the period, as well as the impact of average condensate prices realized of approximately \$69.00/bbl in the second quarter.

Revenue

Revenue before other income for the second quarter of 2007 was \$73.7 million, 75% greater than the \$42.1 million in the same period of 2006. The higher revenue for the quarter was the result of significant growth in production volumes for natural gas, crude oil, condensate and NGLs due to 2006 acquisitions, in addition to overall higher natural gas prices.

(\$000s)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Light crude oil and condensate	10,293	7,193	17,877	15,868
NGLs	3,426	1,471	5,517	2,749
Heavy oil	11,967	10,353	26,329	16,330
Crude oil and NGLs	25,686	19,017	49,723	34,947
Natural gas	48,058	23,061	95,040	53,575
Total revenue before other	73,744	42,078	144,763	88,522
Other	1,247	926	1,424	878
Total revenue before royalties and hedging	74,991	43,004	146,187	89,400
Gain (loss) on commodity contracts	5,835	(273)	6,514	(273)
Total revenue before royalties	80,826	42,731	152,701	89,127

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.

As of August 8, 2007, the Trust has hedged volumes of 2,000 bbls/d of crude oil and 25,000 GJ/d of natural gas for the third quarter 2007, 2,000 bbls/d of crude oil and 15,055 GJ/d of natural gas for the fourth quarter 2007, 2,000 bbls/d of crude oil and 5,000 GJ/d of natural gas for the first quarter of 2008, and 1,000 bbls/d of crude oil for the second to fourth quarters of 2008. 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 is shown in the following tables (see Note 19 to the consolidated financial statements for a detailed disclosure of all commodity contracts in place as at August 8, 2007):

Crude oil and liquids	Average Volumes (bbls/d)			
	Q3 2007	Q4 2007	Q1 2008	Q2-Q4 2008
Costless collars	-	2,000	2,000	1,000
Put option (price floor)	2,000	-	-	-
Total bbls/d	2,000	2,000	2,000	1,000

Average Price (US\$/bbl WTI)

	Q3 2007	Q4 2007	Q1 2008	Q2-Q4 2008
Collar ceiling price	-	75.00	75.00	82.00
Collar floor price	-	65.00	65.00	65.00
Put option price floor	60.00	-	-	-

Natural gas Average Volumes (GJ/d)

	Q3 2007	Q4 2007	Q1 2008	Q2-Q4 2008
Costless collars	15,000	8,370	5,000	-
Fixed	10,000	6,685	-	-
Total GJ/d	25,000	15,055	5,000	-

Average Price (\$/GJ AECO C)

	Q3 2007	Q4 2007	Q1 2008	Q2-Q4 2008
Collar ceiling price	9.29	9.20	9.05	-
Collar floor price	7.00	7.40	8.00	-
Fixed	7.05	7.03	-	-

The following is a summary of the gain (loss) on commodity contracts for the three and six months ended June 30, 2007:

Commodity contracts

	Crude Oil & Liquids	Natural Gas	Q2 2007 Total	Q2 2006 Total
(\$000s)				
Realized cash gain (loss) on contracts ⁽¹⁾	(384)	266	(118)	(273)
Unrealized gain (loss) on contracts	(251)	6,204	5,953	-
Total gain (loss) on commodity contracts	(635)	6,470	5,835	(273)

	Crude Oil & Liquids	Natural Gas	YTD 2007 Total	YTD 2006 Total
(\$000s)				
Realized cash gain (loss) on contracts ⁽²⁾	1,063	1,963	3,026	(273)
Unrealized gain (loss) on contracts	(343)	3,831	3,488	-
Total gain (loss) on commodity contracts	720	5,794	6,514	(273)

⁽¹⁾ Includes crude oil and natural gas commodity contract premiums expensed in the period and the amortization of prior year crude oil and natural gas commodity contract premiums of a total \$1.0 million for the three month period ended June 30, 2007.

⁽²⁾ Includes crude oil and natural gas commodity contract premiums expensed in the period and the amortization of prior year crude oil and natural gas commodity contract premiums of a total \$3.4 million for the six month period ended June 30, 2007.

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 six month period June 30, 2007, and 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 unaudited interim consolidated financial statements of the Trust for the six months ended June 30, 2007.

Royalties

For the three months ending June 30, 2007, total royalties were \$9.8 million, compared to \$9.7 million incurred in the same period in 2006. Overall royalties as a percentage of revenue (after transportation costs) in the second quarter of 2007 were 14%, compared with 24% in the same period in 2006. The average royalty rate of 14% for the quarter includes the impact of the reversal of certain overaccruals of heavy crude oil and natural gas royalties from prior periods of approximately \$5.3 million. The Trust has grown significantly in the past two years and has acquired a significant number of new properties. 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. Excluding this adjustment for a reduction to prior period royalties, the average royalty rate, as a percentage of revenue after transportation costs, for the second quarter of 2007 would have been approximately 22%, which is consistent with the weighted average royalty rate anticipated on a go-forward basis.

Royalties by Commodity Type <i>(\$000s, except where noted)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Light crude oil and condensate	1,623	873	1,874	2,392
\$/bbl	10.23	8.55	6.34	9.53
Average light crude oil and condensate royalty rate (%)	16	13	10	16
NGLs	2,034	311	2,663	619
\$/bbl	30.00	11.96	21.89	12.04
Average NGLs royalty rate (%)	59	21	48	23
Heavy Oil	1,416	2,513	2,936	3,612
\$/bbl	5.08	12.37	4.38	8.31
Average heavy oil royalty rate (%)	13	25	12	23
Natural Gas	4,728	5,960	17,222	13,675
\$/mcf	0.74	1.55	1.35	1.77
Average natural gas royalty rate (%)	10	27	18	26
Total	9,801	9,657	24,695	20,298
\$/boe	6.29	9.92	7.67	10.03
Average total royalty rate (%)	14	24	17	24

Royalties, by Type

Royalties, by Type <i>(\$000s)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Crown royalties, net of ARTC	6,229	5,759	13,234	12,894
Indian Oil and Gas Canada royalties	762	631	3,311	1,413
Freehold & GORR	2,810	3,267	8,151	5,991
Total	9,801	9,657	24,695	20,298

Expenses

Expenses <i>(\$000s)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Production	19,778	9,321	34,750	18,488
Transportation	2,431	1,490	3,120	2,463
General and administrative	4,332	3,810	9,236	6,407
Interest and financing charges	4,573	1,847	9,120	3,610
Unit-based compensation	1,275	1,641	2,387	3,051

Expenses per boe

(\$ per boe)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Production	12.69	9.58	10.79	9.14
Transportation	1.56	1.53	0.97	1.22
General and administrative	2.78	3.91	2.87	3.16
Interest and financing charges	2.93	1.90	2.83	1.78
Unit-based compensation	0.82	1.69	0.74	1.51

Production Expenses

For the three months ended June 30, 2007, production expenses totaled \$19.8 million, compared to \$9.3 million recorded in 2006. During the second quarter of 2007, production expenses averaged \$12.69/boe, compared to \$9.58/boe over the same period in 2006. For the first quarter, production expenses averaged \$9.00/boe. The large increase in second quarter costs was due to an underaccrual of prior period costs of approximately \$4.9 million, with approximately \$3.1 million relating to 2006 and prior periods and with approximately 53% of the total attributable to properties acquired from the Prairie Schooner acquisition in September 2006. The majority of the total prior period costs relate to third party and joint venture billings for gathering and processing fees. The Trust has revised its estimates going forward based upon the latest available information. This increase in production expenses is also generally due to a different property mix; recent reduced production volumes have also increased production expenses on a per boe basis because of a significant fixed component of production expenses. Excluding the impact of prior period costs, production expenses would have been approximately \$9.55/boe. Production expenses are expected to increase later in the fourth quarter of 2007 as additional natural gas input costs are required to operate the Kerrobert SAGD facility after startup.

Production Expenses, by Commodity Type

(\$000s, except where noted)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Light crude oil and condensate	1,833	1,784	4,168	3,650
\$/bbl	11.56	17.49	14.11	14.56
NGLs	418	489	600	719
\$/bbl	6.17	18.81	4.93	13.98
Heavy oil	5,612	1,974	11,017	3,901
\$/bbl	20.17	9.72	16.44	8.98
Natural gas	11,915	5,074	18,965	10,218
\$/mcf	1.89	1.32	1.48	1.32
Total	19,778	9,321	34,750	18,488
\$/boe	12.69	9.58	10.79	9.14

Transportation

Transportation costs are expected to be approximately 2% to 3% of gross revenues for the 2007 year. For the second quarter of 2007, transportation costs averaged 3%, which is consistent with expectations.

Operating Netback

For the second quarter of 2007, corporate field operating netback (before hedging) was \$26.79/boe compared to \$22.20/boe in 2006. This was a result of increased commodity prices and reduced average royalties due to prior period royalty adjustments, both of which were offset somewhat by adjustments for prior period operating costs. By comparison, corporate field operating netback (before hedging) for the first quarter of 2007 was \$24.35/boe. After including hedging activities, corporate field operating netback for the second quarter was \$30.53/boe compared to \$21.92/boe in 2006.

Field Operating Netback – Corporate (before hedging)

(\$/boe)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Sales	47.33	43.23	44.96	43.74
Transportation	(1.56)	(1.53)	(0.97)	(1.22)
Royalties	(6.29)	(9.92)	(7.67)	(10.03)
Production expense	(12.69)	(9.58)	(10.79)	(9.14)
Field operating netback	26.79	22.20	25.53	23.35

Field operating netback for natural gas for the second quarter of 2007 increased 62% to \$4.68/mcf, compared to \$2.89/mcf for 2006, reflecting the stronger natural gas prices experienced in addition to prior period royalty and production cost adjustments. After including hedging activities, field operating netback for natural gas for the first quarter of 2007 was \$5.71/mcf compared to \$2.89/mcf in 2006.

Field Operating Netback - Natural Gas (before hedging)

(\$/mcf)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Sales	7.60	5.98	7.43	6.94
Transportation	(0.29)	(0.22)	(0.22)	(0.18)
Royalties	(0.74)	(1.55)	(1.35)	(1.77)
Production expense	(1.89)	(1.32)	(1.48)	(1.32)
Field operating netback	4.68	2.89	4.38	3.67

Field operating netback for crude oil and NGLs averaged \$24.03/bbl for the second quarter of 2007, down 24% compared to \$31.58/bbl for 2006, compared to a 10% decrease in the crude oil and NGLs sales price. Prior period adjustments recorded in the quarter for royalties and production expenses contributed primarily to a temporary increase in field operating netback for crude oil and NGLs. After including hedging activities, field operating netback for crude oil and NGLs was \$22.77/boe compared to \$30.76/boe in 2006.

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

(\$/bbl)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Sales	50.90	57.43	45.74	47.44
Transportation	(1.23)	(1.85)	(0.30)	(1.49)
Royalties	(10.06)	(11.17)	(6.87)	(8.99)
Production expense	(15.58)	(12.83)	(14.52)	(11.23)
Field operating netback	24.03	31.58	24.05	25.73

General and Administrative

Net general and administrative expenses for the three and six months ended June 30, 2007 were \$4.3 million and \$9.2 million, respectively, compared to \$3.8 million and \$6.4 million, respectively, for the same periods in 2006.

The increase in the G&A expense from the respective 2007 periods as compared to the same periods in 2006 is consistent with the increase in staffing levels, higher compensation and other administrative costs as a result of two acquisitions completed in 2006. The decrease in G&A on a per boe basis is consistent with additional production volumes from those same acquisitions.

General and Administrative Expenses

(\$000s, except where noted)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Gross expenses	5,872	5,117	12,282	8,930
Capitalized	(1,121)	(886)	(1,814)	(1,422)
Recoveries	(419)	(421)	(1,232)	(1,101)
Net expenses	4,332	3,810	9,236	6,407
Net expenses, per unit (\$/boe)	2.78	3.91	2.87	3.16

G&A expenses for the six month period ended June 30, 2007 do not include the costs of the March 30, 2007 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 \$4.6 million of interest and financing charges in the three months ended June 30, 2007 compared to \$1.8 million in the same period of 2006. For the six months ended June 30, 2007, interest and financing charges were \$9.1 million compared to \$3.6 million in the same period in 2006. The increase in interest and financing charges for both the three and six month periods ended June 30, 2007 compared to the same periods in 2006 is consistent with the increase in bank debt. True's net debt at June 30, 2007 of \$221.0 million includes the \$78.6 million liability portion of convertible debentures, \$142.2 million of bank debt and the balance a working capital deficiency.

Interest and Financing Charges

(\$000s, except where noted)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Interest and financing charges	4,573	1,847	9,120	3,610
Interest and financing charges (\$/boe)	2.93	1.90	2.83	1.78
Net debt including convertible debentures at quarter end	221,045	129,521	221,045	129,521
Debt to periods cash flow from operations ratio annualized	1.6x	2.0x	1.8x	1.8x
Net debt excluding convertible debentures at quarter end	142,409	48,353	142,409	48,353
Debt to periods cash flow from operations ratio annualized	1.0x	0.7x	1.1x	0.7x

Unit-Based Compensation

Non-cash unit-based compensation expense for the three and six months ended June 30, 2007 was \$1.3 million and \$2.4 million, respectively, compared to \$1.6 million and \$3.0 million in 2006, respectively. The slight decrease in the 2007 expense for both periods reflects reduced incentive rights being granted in the first six months of 2007, compared to the same period in 2006, in addition to a reduction in the estimated weighted average fair value of incentive rights granted for more recent options.

Capital Expenditures

True invested \$15.5 million on exploration and development activities during the second quarter of 2007, compared to \$17.4 million in the same period in 2006. Following the execution of True's extensive Q1 drilling program of 34 (24.0 net) wells, the main focus for the second quarter was on completions and tie-ins of first quarter drills and further upgrades to the Kerrobert SAGD facility. During the second quarter of 2007, True successfully drilled 1 (0.8 net) natural gas well in the Pembina area of West Central Alberta.

Capital Expenditures

(\$000s)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Lease acquisitions and retention	711	657	1,502	2,532
Geological and geophysical	(3,455)	197	3,464	861
Drilling and completion costs	15,661	12,722	48,920	30,007
Facilities and equipment	2,586	3,792	7,458	6,429
Exploration and development	15,503	17,368	61,344	39,829
Corporate and property acquisitions	649	68	1,354	192
Total capital expenditures – cash	16,152	17,436	62,698	40,021
Property dispositions – cash	(9,026)	(24,514)	(27,469)	(24,514)
Total net capital expenditures – cash	7,126	(7,078)	35,229	15,507
Corporate acquisitions – non-cash	-	47,529	-	47,529
Other – non-cash ⁽¹⁾	311	(208)	(313)	427
Corporate acquisitions and other	311	47,321	(313)	47,956
Total capital expenditures	7,437	40,243	34,916	63,463

⁽¹⁾ Other includes current period's asset retirement obligations and unit based compensation capitalized.

True holds an extensive land base. At June 30, 2007, True has approximately 649,000 net undeveloped acres of land of its total developed and undeveloped net acreage position of 1,057,000 net acres in Saskatchewan, Alberta, and British Columbia.

Dispositions during the first six months of 2007 consist of three separate oil and gas property sales involving areas outside of the Trust's core areas for future development. On March 30, 2007, True closed the sale of its Columbia/Minehead and Sylvan Lake, Alberta properties. The net proceeds received on these property sales after adjustments was an aggregate of \$18.4 million. On May 15, 2007, closed the sale of its Gage, Alberta properties. The net proceeds received on this property sale after adjustments was \$9.0 million.

The Trust continues to evaluate further opportunities with its divestiture program.

Subsequent to June 30, 2007, True closed the sale of two minor properties. The net proceeds received on both of the property sales after adjustments was \$0.8 million and was used to pay down debt.

At the end of the second quarter of 2007, the Trust had committed to drill a total of 2 wells in Alberta and recomplete 1 well in Alberta with varying commitment dates up to March 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 \$3.5 million.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion (site restoration) expense for the second quarter of 2007 was \$45.4 million, compared to the \$27.5 million for the same period in 2006, reflecting the acquisition of Shellbridge at the end of June 2006, Prairie Schooner in September 2006 in conjunction with increased production volumes and True's active drilling program over 2006 and 2007. True's DD&A rate for the second quarter of 2007 of \$29.11/boe was higher than \$28.56/boe DD&A rate for the first quarter of 2007, which reflects the adjustment to reserves after 2007 property dispositions.

For the six month period ended June 30, 2007, True has excluded from the depletion calculation \$44.1 million for undeveloped land and \$48.3 million for estimated salvage.

Depletion, Depreciation and Accretion Costs

(\$000s, except where noted)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Depletion	44,738	22,592	90,374	47,755
Depreciation	84	4,732	1,395	8,569
Accretion	527	206	1,038	418
Total	45,349	27,530	92,807	56,742
Per unit (\$/boe)	29.11	28.28	28.83	28.04

The Trust's independent reserve report effective December 31, 2006 is summarized in its Annual Information Form and can be found at www.sedar.com.

Ceiling Test

The Trust calculates a ceiling test quarterly and annually whereby the carrying value of petroleum and natural gas properties is compared to estimated future cash flow from the production of proved reserves. 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 June 30, 2007 resulting in undiscounted cash flows from proved reserves and the 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 of unproved 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.

At June 30, 2007, the Trust calculated the ceiling test using weighted average prices of \$38.92/bbl for heavy oil, \$64.45/bbl for light and medium gravity oil, and \$39.80/bbl for NGLs, and \$7.71/mcf for natural gas.

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 plan of arrangement was not approved.

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 six month period ended June 30, 2007.

Asset Retirement Obligation

As at June 30, 2007, the Trust has recorded an Asset Retirement Obligation ("ARO") of \$27.1 million, compared to \$11.8 million at June 30, 2006, for future abandonment and reclamation of the Trust's

properties. For the six month period ended June 30, 2007, the ARO decreased by \$0.5 million total as a result of accretion expense of \$1.0 million, and \$0.4 million net changes in estimates and liabilities incurred on development activities, offset by \$0.9 million of liabilities released on dispositions.

Income Taxes

For the first six months of 2007, the Trust has recorded a provision for capital taxes of \$1.1 million compared to \$1.5 million expensed in the same period 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, capital taxes on a go-forward basis 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 first six months of 2007, the Trust recognized a future income tax recovery provision of \$21.5 million compared to a recovery provision of \$39.1 million in the same period in 2006. The larger recovery for the 2006 period was primarily reflective of more significant enacted tax rate reductions in 2006. On April 10, 2006 the Alberta government enacted a decrease of 1.5 percent to the provincial corporate tax rate. In addition, 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. In addition, on June 12, 2007, the federal government further reduced the general corporate tax rate by 0.5 percent starting 2011.

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, 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 on 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 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 our cash flow or distributions and is not expected to affect our 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, we can increase our equity by approximately \$737 million between now and 2011 without prematurely triggering the SIFT tax.

Under the SIFT tax, distributions will not be deductible for income tax purposes by SIFTs in 2011 and thereafter and any trust level taxable income will be taxed at an approximate of the corporate income tax rate. The resultant distributions will be considered taxable dividends to unitholders, generally eligible for the dividend tax credit. Distributions representing a return of capital will continue to be an adjustment to a unitholder’s adjusted cost base of trust units.

Our Board of Directors and Management continue to review the impact of this tax on our 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 after-tax distribution yield in 2011 to taxable Canadian investors will remain approximately the same, however, the distribution yield in 2011 to tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors would fall by an estimated 31.5 percent and 26.5 percent, respectively;
- 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.

The table below, provided by the Government of Canada in a backgrounder accompanying its October 31, 2006 announcement, shows a simplified comparison of the effects of the changes to investor tax rates in 2011:

Investor	Current System		Proposed System	
	Income portion of trust distributions	Large corporation (dividend)	Income portion of trust distributions	Large corporation (dividend)
Taxable Canadian individuals (1)	46%	46%	45.5%	45.5%
Canadian tax-exempt investors	0%	32%	31.5%	31.5%
Taxable U.S. investors (2)	15%	42%	41.5%	41.5%

(1) All rates in the table are as of 2011, and include both entity- and investor-level tax (as applicable). Rates for “taxable Canadian individuals” assume that top personal income tax rates apply and that provincial governments increase their dividend tax credit for dividends of large corporations.

(2) Canadian taxes only. U.S. tax will also apply in most cases, net of any foreign tax credits.

As at June 30, 2007, the operating subsidiaries and the Trust itself have a total future income tax liability balance of \$102.5 million. Canadian GAAP requires that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools. It further requires that a future tax liability be recorded on an acquisition when a corporation acquires assets with associated tax pools that are less than the purchase price.

At June 30, 2007 the Trust and operating subsidiaries of the Trust had approximately \$507 million, net of partnership deferrals, in tax pools available for deduction against future income as follows:

<i>(\$000s)</i>	Trust	Operating subsidiaries	Total
Intangible resource pools (net of partnership deferrals)	15,105	331,946	347,051
Undepreciated capital cost	-	140,379	140,379
Loss carryforwards (expire through 2026)	-	5,624	5,624
Unit issue costs	8,262	5,499	13,761
Other	-	243	243
	23,367	483,691	507,058

Distributions

Trust unitholders who held their trust units throughout the first six months of 2007 received distributions of \$0.48 per unit. For the six month period ended June 30, 2007 the Trust declared \$35.2 million in total distributions as follows:

<i>(\$000s, except per unit amount)</i>	Distribution Per Unit	Total
Six month period ended June 30, 2007		
Distributions declared	\$ 0.48	\$ 35,242

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 ⁽³⁾	2.640	2.033	0.607
Cumulative to Dec. 31, 2006	\$ 3.120	\$ 2.489	\$ 0.631
2007 year to date	0.480	⁽³⁾	⁽³⁾
Cumulative to June 30, 2007	\$ 3.600		

⁽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⁾ The majority of the distributions paid in 2007 to Canadian unitholders will be taxable. U.S. unitholders will also be taxable. 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 experienced throughout the year. The approximate taxable portion of 2007 distributions to Canadian unitholders is currently estimated to be between 90 to 100%.

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 March 7, 2007 press release addressing this.

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 ⁽¹⁾	August 31, 2007	September 17, 2007	0.08 ⁽²⁾
September 26, 2007 ⁽¹⁾	September 28, 2007	October 15, 2007	0.08 ⁽²⁾

⁽¹⁾ Anticipated ex-distribution dates for August and September. These dates are subject to change and/or confirmation by the Toronto Stock Exchange and will be confirmed by monthly press release.

⁽²⁾ Subject to confirmation, the Management and Board of the Trust continuously assesses distribution levels, in light of current commodity prices, hedge positions, production volumes, market conditions and other factors, and announces the distribution per unit amount on a monthly basis.

During the first six months of 2007, the distributions were funded directly from cash flows from operating activities.

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 quarter of 2007, monthly distributions of \$0.08 per unit were declared and paid on May 15, 2007, June 15, 2007 and July 16, 2007. Further, the Board has announced it has set a distribution policy for the third quarter of 2007 at a monthly rate of \$0.08 per unit, subject to monthly confirmation, based on current commodity prices, hedging program, production volumes and market conditions. This go-forward strategy for the distribution level is consistent with providing a balance between providing income to unitholders and funding for True's capital program required to further develop its land base.

Foreign Ownership Update

Based on information from Trust records and information provided by intermediaries holding Trust units for others, we estimate that, as of July 18, 2007 approximately 29 percent of our 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

On May 31, 2007, the Trust completed its offering, including an over-allotment option, for an aggregate of 9,430,000 trust units at \$6.10 per unit 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.

True's net debt as at June 30, 2007 was \$221.0 million, representing \$142.2 million outstanding on the credit facility, \$78.6 million in convertible debentures (liability component) and the balance a net working capital deficiency.

During the six month period ended June 30, 2007, the Trust has reduced its net debt by approximately \$54.8 million. As at June 30, 2007, the working capital deficiency has been reduced to \$0.3 million from \$36.3 million at December 31, 2006. This was achieved as a result of many factors including the proceeds received from the Trust's recent equity offering, proceeds received from three property dispositions, maintaining sustainable distributions compared to cash flows from operations and capital expenditure requirements in the period and continued execution of the Trust's hedging program.

The current credit facility consists of a \$15 million demand operating facility provided by one Canadian bank and a \$185 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. Further details of the credit facilities are disclosed in note 7 of the consolidated financial statements. As at June 30, 2007, there is approximately \$57 million undrawn under these lending facilities.

Management expects to be able to fund the \$80 million capital expenditure program for 2007 using cash flow from operations, available credit facilities, the proceeds from the expected sale of certain non-core assets, and the maintenance of sustainable distributions. If cash flows are other than projected, capital expenditure levels are expected to be adjusted. The practice of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required.

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 July 31, 2007 the Trust had outstanding a total of 6,565,665 incentive units exercisable at an average exercise price of \$11.23 per unit, 390,813 exchangeable shares (convertible, as at July 31, 2007 into an aggregate of 306,878 trust units, subject to further adjustments based on distributions made on trust units) and 79,715,595 trust units.

On February 13, 2007, True announced it had identified certain small, non-core properties, for possible disposition. The proceeds will be used to fund capital expenditures and pay down debt. The Trust closed on two dispositions at the end of the first quarter and an additional disposition in May 2007. Subsequent to June 30, 2007, True closed on the sale of two minor properties for total net proceeds after adjustments of \$0.8 million, which was used to pay down debt. The Trust will continue to evaluate opportunities under its divestiture program.

Business Prospects and 2007 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.

Late in September 2006, the Trust completed the purchase of a facility in the Kerrobert, Saskatchewan area and wells which has allowed the Trust to begin implementation of the steam assisted gravity drainage ("SAGD") phase of the project. Continuing through June 2007, the Trust converted a number of existing wells to steam injectors and drilled additional wells that will be used as producing well bores. During the first quarter of 2007, True completed its initial drilling campaign of five cold producers and four thermal wells. All five cold producers are on-line, currently averaging 60 bbls/d per well. The four thermal wells are cased and awaiting equipping prior to the conversion and subsequent steaming of the paired injectors. Execution of the SAGD project is on track with expected steam injection for phase one to commence at the end of the third quarter. Capital expenditure levels will be adjusted as appropriate. The remainder of the 2007 capital program will emphasize True's core areas of West Central Alberta and West Central Saskatchewan. These expenditures will be mainly in the third quarter, following up on successful development campaigns in the first quarter. It will include facility modifications and conversion of existing producers to steam injection service at the Kerrobert SAGD project. Continued participation in

what has been a highly successful non-operated drilling program in West Central Alberta will also carry on in the third quarter.

During the first quarter of 2007, new Kerrobert thermal wells were drilled and facility upgrades continued throughout the second quarter. Execution of the Kerrobert SAGD project is on track with expected steam injection for phase one to commence at the end of the third quarter. We are forecasting that the third quarter will be negatively impacted by additional major third party plant turnarounds in West Central Alberta. Approximately 2,000 boe/d of production will be shut-in for a period during the third quarter from our Willesden Green properties. During the shut-in period the Trust will gather extensive pressure data on the tight gas reservoirs and execute a number of workovers. The remaining behind pipe production, workovers, and the Kerrobert SAGD start-up will provide visible growth prior to the end of the 2007 year. With these forecasted turnarounds and completed dispositions the Trust is anticipating 2007 annual average volumes of approximately 17,000 boe/d, weighted approximately 67% towards natural gas.

True further anticipates the US\$/Cdn.\$ exchange rate to average 0.91 through the 2007 year.

The Trust continues to maintain a large undeveloped land base of approximately 0.9 million (0.6 million net) acres and has identified a multi-year drilling inventory of over 450 net locations.

Business Risks and Uncertainties

The reader is advised that True continues to be subject to various types of business risks and uncertainties as described in the Management Discussion and Analysis in the Trust's December 31, 2006 Annual Report and the Trust's Annual Information Form. In addition, the Trust is also subject to the following business risks and uncertainties:

Environmental Regulation and Risk

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. 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.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and 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. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options

are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 8, 2007, the Alberta Government introduced Bill 3, the Climate Change and Emissions Management Amendment Act, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay \$15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

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

Review of Alberta Royalty and Tax Regime

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007. At this time, the Trust cannot determine the potential impact of any changes to the royalty rate on its operations.

Critical Accounting Estimates

The reader is advised that the critical accounting estimates, policies, and practices as described in the Management Discussion and Analysis in the Trust's December 31, 2006 Annual Report continue to be critical in determining True's unaudited financial results as at June 30, 2007. Except as described in Note 3 of the attached unaudited interim consolidated financial statements, there were no changes in accounting policies for the six month period ended June 30, 2007.

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.

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 June 30, 2007, that has materially affected, or are reasonably likely to materially affect, the Trust's internal control of 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.

Sensitivity Analysis

The table below shows sensitivities to cash flow as a result of product price and operational changes. This is based on actual prices received for the three month period ended June 30, 2007 and average production volumes of 17,122 boe/d during that period, as well as the same level of debt outstanding at June 30, 2007. Diluted weighted average trust units is based upon the second 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:

	Cash Flow from Operations (annualized) (\$000s)	Cash Flow from Operations Per Diluted Unit (\$)
Sensitivity Analysis		
Change of US \$1/bbl WTI	1,400	0.02
Change of \$0.10/ mcf	2,000	0.03
Change of US \$0.01 Cdn/ US exchange rate	1,200	0.02
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 most recently completed quarters ending at the second quarter of 2007.

2007 – Quarter ended (unaudited) (\$000s, except per unit amounts)	March 31	June 30
Revenues before royalties and hedging	71,196	74,991
Cash flow from operations ⁽¹⁾	29,988	34,192
Cash flow from operations per unit ⁽¹⁾		
Basic	\$0.43	\$0.47
Diluted	\$0.42	\$0.45
Net income (loss)	(8,571)	1,741
Net income (loss) per unit		
Basic	\$(0.12)	\$0.02
Diluted	\$(0.12)	\$0.02
Net capital expenditures (cash)	28,103	7,126
Distributions declared	16,866	18,376
Distributions per unit	\$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
Cash flow from operations ⁽¹⁾	18,995	16,386	23,225	31,785
Cash 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)	22,585	(7,078)	46,166	30,341
Distributions declared	26,150	27,771	36,846	33,588
Distributions per unit	\$0.72	\$0.72	\$0.72	\$0.48
<hr/>				
2005 – Quarter ended (unaudited) ⁽²⁾ (\$000s, except per unit amounts)	March 31	June 30	Sept. 30	Dec. 31
Revenues before royalties and hedging	22,441	33,663	44,510	61,056
Cash flow from operations ⁽¹⁾	10,732	18,013	25,500	32,892
Cash flow from operations per unit ⁽¹⁾				
Basic	\$0.63	\$0.73	\$1.04	\$1.02
Diluted	\$0.61	\$0.72	\$1.01	\$1.00
Net income (loss)	1,030	3,130	6,502	3,228
Net income (loss) per unit				
Basic	\$0.06	\$0.13	\$0.26	\$0.10
Diluted	\$0.06	\$0.13	\$0.26	\$0.10
Net capital expenditures (cash)	13,161	21,316	28,651	52,843
Distributions declared	-	-	-	17,361
Distributions per unit ⁽²⁾	-	-	-	\$0.48

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

⁽²⁾ restated for changes in accounting policies and to reflect the consolidation of units effective November 2, 2005.

The reasons for differences in results experienced from the first quarter of 2007 to the second quarter of 2007 are described previously in this report.

The quarterly results as presented for 2005 and 2006 varied significantly for two main reasons: 1) the timing of acquisitions during 2005 and 2006 and 2) changes in commodity prices over those periods.

During 2005, True completed two acquisitions. The acquisition of Meridian Energy Corporation was closed effective March 15, 2005 and the reverse takeover of TKE Energy Trust closed on November 2, 2005. In addition, True completed the purchases of Shellbridge and Prairie Schooner on June 23, 2006 and September 22, 2006, respectively.

True's revenue, net income, and cash flow from operations over 2005 and 2006 has reflected its production base after considering the timing of the above noted acquisitions, the results of ongoing drilling activities, as well as the changes in commodity prices, primarily that for natural gas. Beginning in the first quarter of 2005 and continuing into the first quarter of 2006, natural gas revenue was gradually increasing which resulted in a corresponding increase in the Trust's petroleum and natural gas revenue, net income and cash flow from operations in the period. This trend started to reverse in the second quarter of 2006 with declining natural gas prices influencing a corresponding relative decrease in the Trust's revenues, net income and cash flows from operations.

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 is due to an increase in its depletable base as a result of the acquisitions and further capital spending. Futures 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. 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.

TRUE ENERGY TRUST
CONSOLIDATED BALANCE SHEETS

As at June 30 and December 31 (unaudited)

(\$000s)	2007	2006
ASSETS		
Current assets		
Accounts receivable	\$ 56,934	\$ 73,199
Deposits and prepaid expenses	3,673	7,928
Capital taxes receivable	1,089	-
Commodity contract asset (note 19)	4,299	-
	<u>65,995</u>	<u>81,127</u>
Property, plant and equipment (note 6)	875,127	931,979
Deferred financing charges (note 8)	-	3,552
Total assets	<u>\$ 941,122</u>	<u>\$1,016,658</u>
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 59,531	\$ 107,431
Distribution payable to unitholders	6,377	8,433
Capital taxes payable	-	1,513
Current portion of obligations under capital lease	-	111
Commodity contract liability (note 19)	343	-
	<u>66,251</u>	<u>117,488</u>
Long-term debt (note 7)	142,153	157,904
Convertible debentures (note 8)	78,636	81,551
Asset retirement obligations (note 9)	27,129	26,605
Future income taxes (note 14)	102,544	123,861
Total liabilities	<u>416,713</u>	<u>507,409</u>
NON-CONTROLLING INTEREST		
Exchangeable shares of subsidiary (note 10)	4,083	4,153
UNITHOLDERS' EQUITY		
Unitholders' capital (note 11)	931,336	876,904
Equity component of convertible debentures (note 8)	5,119	5,119
Contributed surplus (note 12)	15,407	12,818
Deficit	(431,720)	(389,745)
Accumulated other comprehensive income	184	-
Total unitholders' equity	<u>520,326</u>	<u>505,096</u>
Total liabilities and unitholders' equity	<u>\$ 941,122</u>	<u>\$ 1,016,658</u>

See accompanying selected notes to the consolidated financial statements.

TRUE ENERGY TRUST

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the three and six months ended June 30 (unaudited)

(\$000s)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
REVENUES				
Petroleum and natural gas sales	\$ 74,991	\$ 43,004	\$ 146,187	\$89,400
Royalties	(9,801)	(9,657)	(24,695)	(20,298)
Gain (loss) on commodity contracts (note 19)	5,835	(273)	6,514	(273)
	<u>71,025</u>	<u>33,074</u>	<u>128,006</u>	<u>68,829</u>
EXPENSES				
Production	19,778	9,321	34,750	18,488
Transportation	2,431	1,490	3,120	2,463
General and administrative	4,332	3,810	9,236	6,407
Interest and financing charges	4,573	1,847	9,120	3,610
Unit-based compensation (notes 11 and 12)	1,275	1,641	2,387	3,051
Depletion, depreciation and accretion	45,349	27,530	92,807	56,742
Special meeting costs (note 15)	-	-	3,805	-
	<u>77,738</u>	<u>45,639</u>	<u>155,225</u>	<u>90,761</u>
LOSS BEFORE TAXES	(6,713)	(12,565)	(27,219)	(21,932)
TAXES (note 14)				
Capital taxes	159	953	1,091	1,524
Future income taxes (recovery)	(8,627)	(25,861)	(21,456)	(39,094)
	<u>(8,468)</u>	<u>(24,908)</u>	<u>(20,365)</u>	<u>(37,570)</u>
NET INCOME (LOSS) BEFORE NON-CONTROLLING INTEREST	1,755	12,343	(6,854)	15,638
Non-controlling interest	14	100	(24)	136
	<u>1,741</u>	<u>12,243</u>	<u>(6,830)</u>	<u>15,502</u>
NET INCOME (LOSS)	<u>1,741</u>	<u>12,243</u>	<u>(6,830)</u>	<u>15,502</u>
Net changes in cash flow hedges (net of tax of \$0.2 million and \$1.8 million, respectively)	(409)	-	(3,565)	-
	<u>\$ 1,332</u>	<u>\$12,243</u>	<u>\$ (10,395)</u>	<u>\$15,502</u>
COMPREHENSIVE INCOME (LOSS)				
Net income (loss) per trust unit				
Basic	\$ 0.02	\$ 0.33	\$ (0.10)	\$ 0.43
Diluted	\$ 0.02	\$ 0.33	\$ (0.09)	\$ 0.42

See accompanying selected notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
For the three and six months ended June 30 (unaudited)

(\$000s)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
UNITHOLDERS' CAPITAL				
Balance, beginning of period	\$ 876,920	\$ 423,149	\$ 876,904	\$418,968
Issued for cash (net of issue costs of \$3.1 million)	54,386	-	54,386	-
Issued to acquire Shellbridge (net of issue costs of \$0.6 million)	-	67,668	-	67,668
Exchangeable shares converted	30	1,813	46	4,677
Units issued pursuant to DRIP	-	13,747	-	15,064
Balance, end of period	931,336	506,377	931,336	506,377
EQUITY COMPONENT OF CONVERTIBLE DEBENTURES				
Balance, beginning of period	5,119	-	5,119	-
Conversion feature on convertible debentures issued	-	5,119	-	5,119
Balance, end of period	5,119	5,119	5,119	5,119
CONTRIBUTED SURPLUS				
Balance, beginning of period	14,000	6,757	12,818	5,127
Unit-based compensation expense (note 12)	1,407	1,967	2,589	3,597
Balance, end of period	15,407	8,724	15,407	8,724
DEFICIT				
Balance, beginning of period	(415,085)	(54,717)	(389,745)	(31,826)
Net income (loss)	1,741	12,243	(6,830)	15,502
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	(18,376)	(27,771)	(35,242)	(53,921)
Balance, end of period	(431,720)	(70,245)	(431,720)	(70,245)
ACCUMULATED OTHER COMPREHENSIVE INCOME				
Balance, beginning of period	593	-	-	-
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 \$0.2 million and \$1.8 million, respectively)	(409)	-	(3,565)	-
Balance, end of period	184	-	184	-
TOTAL UNITHOLDERS' EQUITY	\$ 520,326	\$ 449,975	\$ 520,326	\$ 449,975

See accompanying selected notes to the consolidated financial statements.

TRUE ENERGY TRUST
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the three and six months ended June 30 (unaudited)

(\$000s)	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Cash provided by (used in):				
CASH FLOW FROM OPERATING ACTIVITIES				
Net income (loss)	\$ 1,741	\$ 12,243	\$ (6,830)	\$ 15,502
Items not involving cash:				
Non-controlling interest (note 10)	14	100	(24)	136
Depletion, depreciation and accretion	45,349	27,530	92,807	56,742
Unit-based compensation (note 12)	1,275	1,641	2,387	3,051
Unrealized gain on commodity contracts (note 19)	(5,953)	-	(3,488)	-
Amortization of deferred financing charges (note 8)	-	35	-	35
Accretion on convertible debentures (note 8)	393	37	784	37
Future income taxes (recovery) (note 14)	(8,627)	(25,861)	(21,456)	(39,094)
Capital taxes	-	661	-	(1,028)
	34,192	16,386	64,180	35,381
Change in non-cash working capital (note 13)	(29,403)	(7,523)	(19,244)	(15,909)
	4,789	8,863	44,936	19,472
CASH FLOW FROM (USED IN) FINANCING ACTIVITIES				
Increase (decrease) in bank debt	(36,226)	(88,019)	(14,731)	(49,531)
Obligations under capital lease	(29)	(50)	(111)	(98)
Issuance of convertible debentures	-	86,250	-	86,250
Deferred financing charges	-	(4,023)	-	(4,023)
Issue of trust units for cash	57,523	-	57,523	-
Unit issue costs	(3,137)	(629)	(3,137)	(629)
Payment of cash component of distributions	(11,999)	(12,721)	(37,298)	(37,495)
	6,132	(19,192)	2,246	(5,526)
Change in non-cash working capital (note 13)	186	893	243	893
	6,318	(18,299)	2,489	(4,633)
CASH FLOW FROM (USED IN) INVESTING ACTIVITIES				
Additions to property, plant and equipment	(16,152)	(17,436)	(62,698)	(40,021)
Corporate transaction costs	-	(520)	-	(520)
Proceeds on sale of property, plant and equipment	9,026	24,514	27,469	24,514
	(7,126)	6,558	(35,229)	(16,027)
Change in non-cash working capital (note 13)	(3,981)	(2,340)	(12,196)	(4,030)
	(11,107)	4,218	(47,425)	(20,057)
Cash acquired on corporate acquisition (note 5b)	-	5,218	-	5,218
Change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying selected notes to the consolidated financial statements.

SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2007 and 2006 (unaudited)

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. Through a Plan of Arrangement (the "TKE Arrangement") that became effective on November 2, 2005, True Energy Inc. became the Trust.

Pursuant to the TKE Arrangement, 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., its wholly owned subsidiary Marengo Exploration Ltd., True Oil & Gas Ltd., True Energy Partnership and TKE Energy Partnership. The Trust owns, directly and indirectly, 100% of the common shares, (excluding the exchangeable shares – see note 10) of True Energy Inc., Marengo Exploration Ltd., True Oil & Gas Ltd. and 100% of the interests of True Energy Partnership and TKE Energy Partnership. The activities of True Energy Inc., Marengo Exploration Ltd., True Oil & Gas Ltd. and the partnerships, 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 Net Profit Interest Agreements (the "NPI Agreements"), the Trust is entitled to a payment from True Energy Inc. and True Oil & Gas Ltd. 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 Agreements, 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., Marengo Exploration Ltd., True Oil & Gas Ltd., True Energy Partnership and TKE Energy Partnership, 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 Agreements, 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 interim consolidated financial statements of the Trust have been prepared by management in accordance with generally accepted accounting policies in Canada. The unaudited interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except as described in note 3. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto contained in the Trust's annual report for the year ended December 31, 2006.

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:

<i>Increase (decrease) (\$000s)</i>	<i>At January 1, 2007</i>
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 18 to the Trust's 2006 annual financial statements 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 will be reclassified to income in future periods 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 7 and to deferred financing costs and the debt component of convertible debentures as disclosed in note 8.

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 continue 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:

<u>(\$000's)</u>	
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Cost of acquisition:	
Trust units issued	\$ 342,870
True transaction costs	1,563
	<hr/>
	\$ 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)
	<hr/>
	\$ 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 continue 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:

<i>(\$000's)</i>	
Cost of acquisition:	
Trust units issued	\$ 68,299
True transaction costs	520
	<hr/>
	\$ 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)
	<hr/>
	\$ 68,819

As at December 31, 2006, a goodwill impairment provision of \$169.8 million was recorded to write-down the goodwill initially recognized from the above and previous year acquisitions.

6. PROPERTY, PLANT AND EQUIPMENT

<i>(\$000s)</i>			
		Accumulated depletion and depreciation	
June 30, 2007	Cost		Net book value
Petroleum and natural gas properties	\$1,347,935	\$ 475,608	\$ 872,327
Office furniture and equipment	3,942	1,142	2,800
	<hr/>	<hr/>	<hr/>
	\$1,351,877	\$ 476,750	\$ 875,127
December 31, 2006			
Petroleum and natural gas properties	\$1,314,374	\$ 384,110	\$ 930,264
Office furniture and equipment	2,588	873	1,715
	<hr/>	<hr/>	<hr/>
	\$1,316,962	\$ 384,983	\$ 931,979

The Trust has excluded \$44.1 million for undeveloped land and \$48.3 million for estimated salvage from the depletion calculation during the six month period ended June 30, 2007.

For the six month period ended June 30, 2007, the Trust capitalized \$2.2 million of general and administrative expenses and \$0.2 million of unit-based compensation expense directly related to exploration and development activities.

7. LONG-TERM DEBT

The Trust has a \$15 million demand operating facility provided by one Canadian bank and \$185 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 \$0.8 million at June 30, 2007, is now netted against long-term debt and amortized on the effective interest basis.

As at June 30, 2007, there was \$10.0 million outstanding under the operating facility and \$133.0 million outstanding under the revolving term credit facility. As at June 30, 2007, there is approximately \$57.0 million undrawn under the facility.

The borrowing base is currently scheduled for renewal on or before August 31, 2007.

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 June 30, 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.

8. 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 six month period ended June 30, 2007 and the year ended December 31, 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)	-	(3,699)	-
Accretion	-	784	-
Balance, June 30, 2007	86,250	\$ 78,636	\$ 5,119

The following table shows the deferred financing charges activities for the six month period ended June 30, 2007 and the year ended December 31, 2006:

Deferred financing charges (\$000s)	June 30, 2007	December 31, 2006
Balance, beginning of period	\$ 3,552	\$ -
Costs incurred for convertible debenture offering	-	3,989
Less amortization in the period	-	(437)
Impact of change in accounting policy for financial instruments on January 1, 2007 (note 3)	(3,552)	-
Balance, end of period	\$ -	\$ 3,552

9. 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 \$73.9 million which will be incurred between 2007 and 2053. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.4 percent were used to calculate the fair value of the asset retirement obligation.

(\$000s)	June 30, 2007	December 31, 2006
Asset retirement obligation, beginning of period	\$ 26,605	\$ 10,457
Liabilities acquired through corporate acquisitions	-	13,704
Liabilities incurred on development activities	390	1,210
Changes in prior period estimates	16	810
Liabilities released on dispositions	(921)	(641)
Accretion expense	1,039	1,065
Asset retirement obligation, end of period	\$ 27,129	\$ 26,605

10. EXCHANGEABLE SHARES OF SUBSIDIARY

	June 30, 2007		December 31, 2006	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of period	403,536	\$ 4,153	788,558	\$ 9,709
Non-controlling interest expense (recovery)	-	(24)	-	(803)
Exchanged for trust units	(4,476)	(46)	(385,022)	(4,753)
Balance, end of period	399,060	\$ 4,083	403,536	\$ 4,153

The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date, and at June 30, 2007 was 0.77486. The exchangeable shares are not eligible for cash distributions; however cash distributions will increase the exchange ratio.

11. UNITHOLDERS' CAPITAL

a. Trust Units of True Energy Trust

	June 30, 2007		December 31, 2006	
	Number	Amount (\$000s)	Number	Amount (\$000s)
Balance, beginning of period	70,275,703	\$ 876,904	36,176,196	\$ 418,968
Issued for cash (net of issue costs of \$3.1 million)	9,430,000	54,386	-	-
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
Exchangeable shares converted	3,416	46	231,035	4,753
Units issued pursuant to DRIP	-	-	3,574,185	42,608
Issued to acquire property interest	-	-	145,358	1,817
Balance, end of period	79,709,119	\$ 931,336	70,275,703	\$ 876,904

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 six month ended and as at June 30, 2007.

Unit Rights Continuity

	Average Exercise Price ^(a)	Number
Balance, December 31, 2006	\$ 14.18	5,429,831
Granted	\$ 6.18	2,080,000
Forfeited	\$ 13.14	(622,332)
Balance, June 30, 2007	\$ 11.46	6,887,499

Unit Rights Outstanding

Exercise Price Before Price Reductions	Exercise Price Net of Reductions	At June 30, 2007	Outstanding Exercise Price Net of Price Reductions ^(b)	Remaining Contractual Life ^(b)	Exercisable	
					At June 30, 2007	Exercise Price Net of Price Reductions ^(b)
\$ 5.89 - \$ 6.70	\$ 5.68 - \$ 6.53	2,053,000	\$ 6.02	4.9	-	N/A
\$10.58 - \$12.53	\$ 9.67 - \$11.52	1,294,500	\$ 9.91	4.3	-	N/A
\$13.74 - \$14.83	\$12.15 - \$13.32	668,500	\$ 12.58	4.0	76,666	12.79
\$15.92 - \$16.70	\$13.85 - \$14.68	150,833	\$ 14.18	3.8	98,334	\$ 14.19
\$18.25 - \$20.98	\$15.67 - \$18.62	2,720,666	\$ 15.86	3.4	1,829,317	\$ 15.86
\$ 5.89 - \$20.98	\$ 5.68 - \$18.62	6,887,499	\$ 11.46	4.1	2,004,317	\$ 15.66

^(a) Exercise prices reflect grant prices less reduction in exercise prices.

^(b) Based on weighted average unit rights outstanding.

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 six months ended June 30, 2007, the Trust matched \$0.2 million under the plan.

12. CONTRIBUTED SURPLUS

(\$000s)	June 30, 2007	December 31, 2006
Balance, beginning of period	\$ 12,818	\$ 5,127
Unit-based compensation expense	2,589	7,691
Balance, end of period	\$ 15,407	\$12,818

Unit-based Compensation

During the six months ended June 30, 2007, the Trust granted 2,080,000 unit incentive rights to employees and directors. During the six months ended June 30, 2007, the Trust recorded unit-based compensation of \$2.6 million, of which \$0.2 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 six month period ended June 30, 2007 and the assumptions used in their determination are as noted below.

Six months ended June 30, 2007	
Assumptions:	
Risk free interest rate (%)	4
Expected life (years)	5
Expected volatility (%)	24
Results:	
Weighted average fair value of incentive rights granted	\$ 1.23

13. SUPPLEMENTAL CASH FLOW INFORMATION

Cash Interest and Taxes Paid

<i>(\$000s)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Cash paid:				
Interest	\$ 6,169	\$ 1,886	\$ 8,729	\$ 2,874
Taxes (net of refunds)	\$ 1,206	\$ 560	\$ 3,699	\$ 3,214

Change in Non-cash Working Capital

<i>(\$000s)</i>	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Changes in non-cash working capital items:				
Accounts receivable	\$ 5,576	\$ 26,551	\$ 16,267	\$ 17,796
Deposits and prepaid expenses	259	(213)	3,042	(599)
Accounts payable and accrued liabilities	(37,986)	(35,308)	(47,904)	(36,243)
Capital taxes receivable/payable	(1,047)	-	(2,602)	-
	\$ (33,198)	\$ (8,970)	\$ (31,197)	\$ (19,046)
Changes related to operating activities	\$ (29,403)	\$ (7,523)	\$ (19,244)	\$ (15,909)
Changes related to financing activities	186	893	243	893
Changes related to investing activities	(3,981)	(2,340)	(12,196)	(4,030)
	\$ (33,198)	\$ (8,970)	\$ (31,197)	\$ (19,046)

14. 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 enactment of the SIFT tax, 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 June 30, 2007, the total "temporary difference" (tax basis exceeds accounting basis) in the Trust is \$11.8 million.

As at June 30, 2007, the Trust's subsidiaries have tax basis of approximately \$484 million that is available to shelter future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of

approximately \$5.6 million that expire in years through 2026. In addition, the Trust has approximately \$23 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 32.94% (2006: 34.19%) to earnings before income taxes.

This difference results from the following items:

(\$000s)	Six months ended June 30,	
	2007	2006
Expected income tax expense (recovery)	\$ (8,966)	\$ (7,499)
Distributions deducted for tax purposes	(10,490)	(13,127)
Impact of SIFT legislation	(1,165)	-
Crown royalties and charges	-	1,956
Resource allowance	-	(1,717)
Unit based compensation expense	786	968
Change in enacted tax rates	(1,725)	(19,305)
Other	104	(370)
Future income tax expense (recovery)	(21,456)	(39,094)
Capital tax expense	1,091	1,524
Total tax expense (recovery)	\$ (20,365)	\$ (37,570)

15. 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 plan of arrangement was not approved.

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 six month period ended June 30, 2007.

16. PER TRUST UNIT AMOUNTS

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Basic trust units outstanding	79,709,119	41,837,743	79,709,119	41,837,743
Dilutive effect of:				
Trust unit incentive rights outstanding	6,887,499	3,552,333	6,887,499	3,552,333
Units issuable for exchangeable shares	309,216	258,445	309,216	258,445
Units issuable for convertible debentures	5,390,625	5,390,625	5,390,625	5,390,625
Diluted trust units outstanding	92,296,459	51,039,146	92,296,459	51,039,146
Weighted average trust units outstanding	73,490,245	37,332,174	71,891,887	36,470,894
Dilutive effect of exchangeable shares, trust unit incentive plan and convertible debentures ⁽¹⁾	2,320,716	1,156,883	309,216	941,528
Diluted weighted average trust units outstanding	75,810,961	38,489,057	72,201,103	37,412,422

⁽¹⁾ A total of 4,875,999 (2006: 3,448,203) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the three month period ended June 30, 2007 as they were not dilutive. A total of 6,887,499 (2006: 3,435,717) trust incentive units and 5,390,625 (2006: nil) trust units issuable pursuant to the conversion of convertible debentures were excluded from the calculation for the six month period ended June 30, 2007 as they were not dilutive.

17. RELATED PARTY TRANSACTIONS

During the six month period ended June 30, 2007, the Trust paid \$1.0 million (2006: \$0.6 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.

18. COMMITMENTS

At the end of the second quarter of 2007, the Trust had committed to drill a total of 2 wells in Alberta and recomplete 1 well in Alberta with varying commitment dates up to March 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 \$3.5 million.

19. FINANCIAL INSTRUMENTS

At June 30, 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	\$ 4,299	\$ 4,299
Commodity contract liability	343	343
Long-term debt	142,153	142,153
Convertible debentures		
Debt component	78,636	
Equity component	5,119	
	<u>83,755</u>	<u>84,956</u>

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 June 30, 2007.

For the six month period ended June 30, 2007, the statement of income included the following:

(\$000s)	2007
Change in fair value of derivative assets and liabilities included in	
Gain on commodity contracts	\$ 6,514
Interest expense	9,120

The Trust has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Oil put option	July 1, 2007 to Sept. 30, 2007	2,000 bbl/d	\$ 60.00 US	-	WTI
Oil collar	Oct. 1, 2007 to March 31, 2008	2,000 bbl/d	\$ 65.00 US	\$ 75.00 US	WTI
Oil collar ⁽¹⁾	April 1, 2008 to Dec. 31, 2008	1,000 bbl/d	\$ 65.00 US	\$ 82.00 US	WTI
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 11.00 CDN	AECO C
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.76 CDN	AECO C
Natural Gas collar	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 8.12 CDN	AECO C
Natural Gas collar	Nov. 1, 2007 to March 31, 2008	5,000 GJ/day	\$ 8.00 CDN	\$ 9.05 CDN	AECO C
Natural Gas fixed	April 1, 2007 to Oct. 31, 2007	5,000 GJ/day	\$ 7.10 CDN	\$ 7.10 CDN	AECO C
Natural Gas fixed	April 1, 2007 to Dec. 31, 2007	5,000 GJ/day	\$ 7.00 CDN	\$ 7.00 CDN	AECO C

⁽¹⁾ This contract was entered into subsequent to June 30, 2007.

For the six month period ended June 30, 2007, the gain (loss) on commodity contracts was comprised of the following:

(\$000s)	Activity in the period	Adjustments for new standards ⁽¹⁾	Total
Gain (loss) on commodity contracts			
Realized ⁽²⁾	\$ 6,144	\$ (3,118)	\$ 3,026
Unrealized ⁽³⁾	(4,950)	8,438	3,488
	\$ 1,194	\$ 5,320	\$ 6,514

⁽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.

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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