



PRESS RELEASE

TRUE ENERGY ANNOUNCES 2004 YEAR END FINANCIAL RESULTS

For Immediate Release

March 10, 2005 – True Energy Inc. (“True” or the “Company”) (TSX: TUI) is pleased to announce its financial results for the three and twelve months ended December 31, 2004.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended Dec. 31 (unaudited)		Twelve months ended Dec. 31	
	2004	2003 ¹	2004	2003 ¹
FINANCIAL				
(\$ except per share amounts)				
Revenue (before transportation)	19,468,883	10,638,609	67,947,589	38,479,449
Cash flow from operations ²	10,304,774	4,493,917	33,945,243	16,012,056
per share - basic	\$0.17	\$0.08	\$0.57	\$0.33
per share – diluted	\$0.16	\$0.08	\$0.56	\$0.32
Net earnings (loss)	2,832,987	(681,982)	8,959,580	4,362,963
per share - basic	\$0.05	(\$0.01)	\$0.15	\$0.09
per share - diluted	\$0.04	(\$0.01)	\$0.15	\$0.09
Capital expenditures, net	17,499,231	7,528,692	54,918,929	20,039,875
Debt, net of working capital			22,157,782	14,460,532
Total assets			108,339,530	64,612,164
Shareholders' equity			55,016,506	31,674,579
Shares outstanding				
Basic	62,097,979	54,044,420	62,097,979	54,044,420
Diluted	66,056,546	57,730,420	66,056,546	57,730,420
Weighted average shares				
Basic	61,942,368	54,043,695	59,617,462	48,335,571
Diluted	63,617,574	55,271,364	60,737,647	49,285,718

		Three months ended Dec. 31		Twelve months ended Dec. 31	
		2004	2003 ¹	2004	2003 ¹
OPERATIONAL					
Daily volumes					
Oil and NGLs	(bbls/d)	2,064	1,598	1,728	1,192
Natural gas	(mcf/d)	23,174	12,908	19,923	10,869
Total (BOE/d)	(6:1)	5,927	3,749	5,048	3,003
Prices (before transportation)					
Oil and NGLs	(\$/bbl)	27.47	24.01	30.76	27.62
Natural gas – before hedge	(\$/mcf)	6.68	5.92	6.65	6.69
Natural gas – after hedge	(\$/mcf)	6.68	5.99	6.65	6.67
Combined	(\$/boe)	35.71	30.85	36.77	35.10
Statistics					
Operating netback	(\$/boe)	20.37	15.53	20.46	18.15
Operating expenses	(\$/boe)	5.10	6.81	5.92	7.44
General & administrative	(\$/boe)	1.42	2.01	1.75	2.47
Royalties as a % of sales		27%	26%	26%	25%

¹ Various 2003 amounts have been restated to reflect changes in accounting policies.

² The financial review contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operations as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. The Company presents cash flow from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share.

FINANCIAL REVIEW

March 10, 2005 - The following financial review of the financial results as provided by the management of True Energy Inc. ("True" or the "Company") should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2004 and 2003 and the unaudited consolidated financial statements for the three months ended December 31, 2004 and 2003. This commentary is based on information available to, and is dated, March 10, 2005. The financial data presented is in accordance with Canadian generally accepted accounting principles in Canadian dollars, except where indicated otherwise.

The term barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel (6 mcf/ bbl) of natural gas to barrels of oil equivalence 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.

This financial review contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than, cash flow from operations or funds flow from operations as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's performance. The Company presents cash flow from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share. The consolidated statements of cash flows in the audited consolidated financial statements present the reconciliation between net earnings and cash flow from operations.

This financial review also contains other terms such as net debt and operating netbacks, which are not recognized measures under GAAP. Management believes these measures are useful supplemental measures of firstly, the total amount of current and long-term debt the Company has 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 income determined in accordance with GAAP as measures of performance. True's method of calculating these measures may differ from other companies, and accordingly, may not be comparable to measures used by other companies.

Additional information relating to True including True's Annual Information Form is on SEDAR at www.sedar.com.

Net Earnings and Cash Flow from Operations

True generated cash flow from operations of \$33.9 million for the year ended December 31, 2004, up 112% from the \$16.0 million produced in the same period of 2003. For the three months ended December 31, 2004, cash flow from operations of \$10.3 million grew 129% compared to \$4.5 million for the fourth quarter of the prior year. Higher commodity prices and increased sales volumes in 2004 compared to 2003 were the primary factors contributing to the increases.

Cash Flow From Operations

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
Cash flow from operations	\$10,304,774	\$4,493,917	\$33,945,243	\$16,012,056
Basic	\$0.17	\$0.08	\$0.57	\$0.33
Diluted	\$0.16	\$0.08	\$0.56	\$0.32

* restated to reflect changes in accounting policies

For the twelve months ended December 31, 2004, net earnings were \$9.0 million, compared to \$4.4 million for the same period in 2003. Net earnings for the fourth quarter of 2004 were \$2.8 million, compared to a net loss of \$0.7 million in the fourth quarter of 2003. The growth in earnings during 2004 compared to 2003 primarily reflects the increased cash flow from operations.

Net Earnings (Loss)

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003*	2004	2003*
Net Earnings (Loss)	\$2,832,987	(\$681,982)	\$8,959,580	\$4,362,963
Basic	\$0.05	(\$0.01)	\$0.15	\$0.09
Diluted	\$0.04	(\$0.01)	\$0.15	\$0.09

* restated to reflect changes in accounting policies

Sales Volumes

Sales volumes for the three months ended December 31, 2004 averaged 5,927 boe/d, up 16% from the 5,130 boe/d produced in the third quarter of 2004, with the tie-in of 17 (14.3 net) gas and 5 (4.6 net) heavy oil wells. For 2004, average daily sales were 5,048 boe/d, an increase of 68% from the 3,003 boe/d produced during 2003.

		Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec 31,	
		2004	2003	2004	2003
Natural gas	(mcf/d)	23,174	12,908	19,923	10,869
Heavy oil	(bbls/d)	1,869	1,329	1,513	964
Light oil & NGLs	(bbls/d)	195	269	215	228
Total crude oil & NGLs	(bbls/d)	2,064	1,598	1,728	1,192
Total BOE/d	(6:1)	5,927	3,749	5,048	3,003

Natural gas sales averaged 23.2 Mmcf/d during the fourth quarter of 2004, compared to 20.5 Mmcf/d in the third quarter of 2004. The weighting toward natural gas averaged 65% in the fourth quarter, compared to 57% in the corresponding period of 2003. In the last quarter of 2004, True tied in 17 (14.3 net) natural gas wells located in the Dodsland, Smiley and Coleville Driver areas of Saskatchewan, and the Goodwin and Thunder areas of Alberta.

Crude oil and natural gas liquids sales in 2004 averaged 1,728 bbls/d, up 45% from 2003 average sales of 1,192 bbls/d. In the fourth quarter crude oil and NGL sales volumes averaged 2,064 bbls/d compared to 1,598 bbls/d during the same period of 2003 and 1,706 bbls/d during the third quarter of 2004. During the quarter, True drilled and tied in 5 (4.6 net) heavy oil wells at Kerrobert and Smiley.

By year end, True had 25 (22.1 net) wells from the 2004 drilling program remaining to be tied in, of which four have been tied in 2005. Based on field estimates, production during the first seven weeks of 2005 has averaged 6,200 boe/d, weighted 65% toward natural gas.

Commodity Prices

The impact of changes in the Canadian dollar from the conversion of US\$ based commodity prices reduced profitability during the fourth quarter of 2004, as the Canadian/ U.S. exchange rate deteriorated 7% from an average of 0.7648 in the third quarter of the year to 0.8202. For the twelve months ending December 31, 2004 the average exchange rate in 2004 was up 8% compared to the same period of 2003, with an 8% change in the fourth quarter of 2004 compared to 2003.

Average Commodity Prices

	Three Months ended Dec. 31, (unaudited)			Twelve Months ended Dec 31,		
	2004	2003*	% Change	2004	2003*	% Change
Exchange rate (US\$/Cdn\$)	0.8202	0.7600	8%	0.7703	0.7164	8%
NYMEX (US\$/mmbtu)	7.24	5.42	34%	6.18	5.49	13%
Alberta spot (\$/mcf)	6.59	5.69	16%	6.45	6.51	-1%
True's average prices (\$/mcf)						
– before transportation & hedge	6.68	5.92	13%	6.65	6.69	-1%
– before transportation & after hedge	6.68	5.99	12%	6.65	6.67	-
WTI (US\$/bbl)	48.31	31.18	55%	41.44	31.10	33%
Edmonton par – light oil (\$/bbl)	57.96	39.82	46%	52.85	43.39	22%
Bow River – heavy oil (\$/bbl)	35.66	28.26	26%	37.25	32.38	15%
True's average prices, before transportation (\$/bbl)						
- light crude & condensate	57.91	40.61	43%	50.21	42.16	19%
- NGLs	48.07	30.35	58%	36.52	30.33	20%
- light crude oil & condensate and NGLs	56.18	39.31	43%	48.16	40.26	20%
- heavy crude oil	24.47	20.92	17%	28.29	24.62	15%
- crude oil & NGLs	27.47	24.01	14%	30.76	27.62	11%

* restated to reflect changes in accounting policies

True's natural gas is primarily sold on the daily spot market, with contracts based on the monthly average historical Alberta spot price. In 2004, the Alberta Spot reference price declined by 1% compared to 2003. Similarly the average price True received in 2004 was roughly the same as in 2003, with sales averaging \$6.65/mcf for its natural gas (before hedging and transportation costs). The average Alberta Spot price during the fourth quarter of 2004 was 16% higher than in the same period in 2003. For the three months ending December 31, 2004, before accounting for transportation costs or hedges, True received an average natural gas price of \$6.68/Mcf, 13% greater than in the same period in 2003.

For heavy crude oil, True received an average price before transportation of \$24.47/bbl during the fourth quarter of 2004, 17% more than in 2003. In comparison, the average reference price for Bow River crude in 2004 was 26% more than the average 2003 price in the same period. By December heavy oil differentials had widened such that Bow River was approximately half of the Edmonton par price, improving in early 2005. For 2004, True's heavy oil price averaged \$28.29/bbl, 15% more than in the prior year. Similarly, the Bow River reference price in 2004 compared to 2003 increased by 15%. Most of the Company's heavy oil is blended with condensate on a 4:1 ratio, causing True's heavy oil price to also reflect changes in the spot price of the condensate.

For light oil, condensate and NGLs, True received an average price of \$56.18/bbl during the last quarter of 2004, 43% more than the average price received in the same period of 2003, reflecting the 46% change in the Edmonton par reference price in this same period. For the year ended December 31, 2004, True's average price was \$48.16/bbl, 20% greater than in 2003, again mirroring the 22% change in the Edmonton par reference price.

Revenue

Revenue before transportation for the twelve months ended December 31, 2004 was \$67.9 million, 77% greater than the \$38.5 million generated in the same period in 2003. During the fourth quarter of 2004, pre-transportation revenue of \$19.5 million was 83% more than the corresponding 2003 period. The higher revenue was the result of significant growth in natural gas weighted production volumes complemented by higher commodity prices, primarily for crude oil.

Revenue (\$000s)

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003*	2004	2003*
Light oil & condensate	856	875	3,354	2,948
NGLs	152	95	429	405
Heavy oil	4,209	2,559	15,671	8,659
Crude oil & NGLs	5,217	3,529	19,454	12,012
Natural gas	14,252	7,028	48,494	26,525
Natural gas hedge	-	81	-	(58)
Total before transportation	19,469	10,638	67,948	38,479
Transportation	(535)	(320)	(1,813)	(919)
Total	18,934	10,318	66,135	37,560

* restated to reflect changes in accounting policies

In 2003 True had a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003 based on an AECO "C" price of Cdn. \$6.08 per gigajoule. In 2004, True did not have any hedges. To date in 2005, True has not put in place any hedges.

Transportation costs continue to average approximately 2% to 3% of gross revenues for the three and twelve month periods ending December 31, 2004 and 2003.

Royalties

For the twelve months ending December 31, 2004, total royalties were \$17.4 million, 83% more than the \$9.5 million incurred in the same period in 2003. In the fourth quarter of 2004, the Company paid \$5.0 million in royalties, compared to \$2.6 million in the comparable period in 2003. As a percentage of pre-hedge sales (after transportation costs) for the three and twelve month periods ending December 31 royalties remained in the 25% to 27% band. In 2004, royalty rates have increased marginally reflecting the combination of higher crude oil prices, True's increased drilling this year under numerous farm-in agreements with overriding royalty obligations, and reaching the maximum royalty free volumes allowed on selected heavy oil wells. In 2004 True did not reach the maximum Alberta Royalty Tax Credit allowed, but expects to early in 2005.

Royalties, by Commodity Type (\$000's)

	Three Months ended Dec.31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003	2004	2003
Light crude oil & condensate	103	156	506	524
NGLs	20	22	82	104
Heavy oil	905	532	3,390	1,846
Natural gas	4,015	1,903	13,411	7,043
Total	5,043	2,613	17,389	9,517

Royalty costs for natural gas increased in 2004 roughly proportionate to the increase in gas revenues, primarily reflecting volume growth. Heavy oil royalties, as a percentage of heavy oil sales, were flat despite increased commodity prices in 2004, with approximately two-thirds of heavy oil production occurring on company-owned freehold lands. The royalty burden for light crude oil and condensate declined in 2004, with the sale of a high royalty burdened property after the first quarter.

Royalties, as a % of Commodity Sales (before hedge, after transportation costs)

	Three Months ended Dec 31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003	2004	2003
Light crude oil & condensate	12	18	15	18
NGLs	13	23	19	26
Heavy oil	22	22	22	22
Natural gas	29	28	28	27
Total	27	26	26	25

Royalties, by Type (\$000s)

	Three Months ended Dec 31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003	2004	2003
Crown royalties	3,289	1,625	11,274	6,228
Freehold & GORR	1,900	971	6,539	3,495
Alberta Royalty Tax Credit	(146)	17	(424)	(206)
Total	5,043	2,613	17,389	9,517

Operating Expenses

In the twelve months ended December 31, 2004, \$10.9 million of operating costs were incurred, compared to \$8.2 million in the same period of 2003. True saw increases in 2004 in labor costs to operate wells, primarily due to the increased number of new wells in the Dodsland and Kerrobert areas. Methanol, chemicals and treating costs also increased, with product costing more combined with the addition of new wells in the Dodsland area. Compressor rental costs increased in 2004 compared to 2003. At Coleville Driver, the addition of a third rental compressor in August 2004 effectively doubled the gas processing capacity for the area. At Smiley, True swapped out a four mmcf/d capacity compressor in January 2004, for a larger rental unit capable of processing six mmcf/d. Partially offsetting these changes were the cost savings during the fourth quarter of 2004 from the purchase of a compressor previously rented in the Dodsland area. Gas processing recoveries declined in 2004, primarily due to the purchase of non-working interest volumes at Coleville at the end of the first quarter.

Despite incremental costs incurred in 2004 in comparison to 2003 for selected items, overall economies of scale from significantly increased volumes have served to reduce per unit costs. Savings in operating costs were also enjoyed. True received transportation rebates for costs previously incurred, less tank cleaning was required, trucking costs for emulsion declined and road and lease maintenance dropped with the less severe weather in comparison to 2003. For the twelve months, operating costs have averaged \$5.92/boe this year, down \$1.52/boe from the \$7.44/boe average cost in 2003. In 2003, operating costs reflected a harsher and more extended spring breakup than usual.

For the three months ended December 31, 2004, operating costs totaled \$2.8 million, compared to \$2.3 million recorded in the same period of 2003. During the fourth quarter of 2004, operating costs averaged \$5.10/boe, down from the \$6.74/boe incurred during the third quarter due to the increased volumes.

Operating costs in 2005 are expected to be similar overall to 2004 costs. Saskatchewan sales will enjoy cost savings as the benefits of Company owned facilities installed at Dodsland in the fourth quarter of 2004 begin to be realized, while costs for Alberta gas sales will increase as third party processing fees are incurred for new production brought on-stream.

Production Costs, by Commodity Type (\$000s)

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec 31,	
	2004	2003	2004	2003
Light crude oil & condensate	184	221	693	613
NGLs	25	25	70	79
Heavy oil	948	698	3,183	2,764
Natural gas	1,627	1,405	6,993	4,695
Total	2,784	2,349	10,939	8,151

Production Costs per Unit, by Commodity Type

		Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
		2004	2003	2004	2003
Light crude oil & condensate	(\$/ bbl)	12.45	10.26	10.38	8.77
NGLs	(\$/ bbl)	8.03	7.85	5.96	5.91
Heavy oil	(\$/ bbl)	5.51	5.71	5.75	7.86
Natural gas	(\$/ mcf)	0.76	1.18	0.96	1.18
Total	(\$/ boe)	5.10	6.81	5.92	7.44

Operating Netbacks

For the twelve month period ending December 31, 2004, True's overall field netback averaged \$20.46/boe compared to \$18.15/boe for the same 2003 period, with reduced operating costs and increased crude oil commodity prices partially offset by increased royalty costs. During the fourth quarter of 2004, company field operating netbacks improved by 31% compared to 2003, driven primarily by increased crude oil sales prices and reduced per unit operating costs partially offset by increased per unit transportation and royalties.

Corporate Field Operating Netbacks

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
<i>\$/boe</i>				
Sales	35.71	30.85	36.77	35.10
Transportation	(0.98)	(0.93)	(0.98)	(0.83)
Royalties	(9.26)	(7.58)	(9.41)	(8.68)
Production expense	(5.10)	(6.81)	(5.92)	(7.44)
Field operating netback	20.37	15.53	20.46	18.15

* restated to reflect changes in accounting policies

Field operating netbacks for natural gas during the fourth quarter of 2004 of \$3.88/Mcf were 27% greater than the 2003 netbacks, reflecting an increased gas price combined with operating costs reductions, despite increased per unit royalty costs. For the twelve-month period, operating netbacks for natural gas increased by a marginal 4% as an improvement in operating costs was tempered by increased royalties.

Field Operating Netbacks Natural Gas

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
<i>\$/Mcf</i>				
Sales	6.68	5.92	6.65	6.69
Hedge	-	0.07	-	(0.01)
Transportation	(0.16)	(0.16)	(0.16)	(0.16)
Royalties	(1.88)	(1.60)	(1.84)	(1.78)
Production expense	(0.76)	(1.18)	(0.96)	(1.18)
Field operating netback	3.88	3.05	3.69	3.56

* restated to reflect changes in accounting policies

Field operating netbacks for crude oil and NGLs during the fourth quarter of 2004 averaged \$14.98/bbl, down from \$21.02/bbl during the third quarter of 2004, as heavy oil differentials sharply widened in November and particularly December. In comparison to the fourth quarter of 2003, True still enjoyed improved crude oil and NGL field operating netbacks primarily from commodity sales prices and operating cost efficiencies. For the 2004 year, crude oil and NGL netbacks have increased by 30% to average \$17.28/bbl through enhanced sales prices combined with operating cost savings.

Field Operating Netbacks Crude Oil & NGLs

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
<i>\$/bbl</i>				
Sales	27.47	24.01	30.76	27.62
Transportation	(0.99)	(0.93)	(0.95)	(0.69)
Royalties	(5.41)	(4.83)	(6.29)	(5.68)
Production expense	(6.09)	(6.42)	(6.24)	(7.95)
Field operating netback	14.98	11.83	17.28	13.30

* restated to reflect changes in accounting policies

General and Administrative

General and administrative expenses for the twelve months ended December 31, 2004 were \$3.2 million compared to \$2.7 million for the same period in 2003. In the fourth quarter of 2004, the net cost of general and administrative charges was \$0.8 million, compared to \$0.7 million in the comparable 2003 period. In 2004, gross costs, amounts capitalized and recoveries have all increased, reflecting the personnel and related supplies required to administer the increased production base while continuing to generate exploration opportunities. On a per unit of production basis, costs in 2004 have declined in both the fourth quarter and for the twelve months ended December 31 when compared to the same periods of 2003, reflecting increased sales volumes.

General and Administrative Costs \$ 000's, except where noted

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
Gross costs	1,571	1,457	6,281	4,676
Capitalized	(408)	(450)	(1,773)	(884)
Recoveries	(388)	(315)	(1,277)	(1,082)
Net costs	775	692	3,231	2,710
Net costs, per unit (\$/boe)	1.42	2.01	1.75	2.47

* restated to reflect changes in accounting policies

General and administrative expenses for the three month period ending December 31, 2003 have been restated to reflect the fourth quarter 2003 adoption of the CICA Handbook Section 3870 "Stock Based Compensation and Other Stock Based Payments" shown on a comparative basis at the beginning of 2003, resulting in decreased costs of \$107 thousand for the fourth quarter. In 2004, stock compensation costs were \$756 thousand, of which \$244 thousand was in the fourth quarter.

Interest Expense

True incurred \$122 thousand of interest expense for the three months ended December 31, 2004 compared to \$119 thousand charged in the same period of 2003. For the twelve months ending December 31, 2004 interest expense was \$528 thousand, down from \$773 thousand in the same period in 2003.

True's costs of borrowing declined in 2004 compared to 2003 with the transition from prime plus one and a quarter percent to a price grid basis dependent on the net debt to cash flow ratio, as determined on a quarter by quarter basis. Further savings during the third quarter of 2004 were realized from lower average bank indebtedness levels compared to the same period in 2003. In the fourth quarter of 2004, average bank indebtedness increased in absolute amounts, but declined in proportion to annualized cash flow.

Interest Costs \$000s, except where noted

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec.31,	
	2004	2003	2004	2003
Interest expense	122	119	528	773
Interest (\$/boe)	0.22	0.34	0.29	0.71
Net debt at quarter end	22,158	14,461	22,158	14,461
Debt to periods cash flow ratio annualized	0.5x	0.8x	0.7x	0.9x

Capital Expenditures

In 2004, True's capital expenditure program was primarily focused on drilling natural gas and heavy oil prospects, complemented by a number of acquisitions within the Company's two core areas, necessitating expansion of natural gas facilities.

Capital expenditures for the twelve months ending December 31, 2004 totaled \$54.9 million, while \$20.0 million was expended in the prior year. During 2004, True drilled 89 (73.9 net) wells with a net success rate of 93%, of which 64 (55.0 net) were gas wells, 15 (11.6 net) were heavy oil wells, two (2.0 net) were light oil wells, and eight (5.3 net) were dry and abandoned. In the year, 66 (62.0 net) wells were drilled in Saskatchewan and 23 (11.9 net) wells were drilled in Alberta.

During the fourth quarter of 2004, True invested \$17.5 million on capital projects, compared to \$7.5 million in 2003. True drilled or participated in 23 (18.9 net) wells during the fourth quarter of 2004, resulting in 17 (13.3 net) natural gas wells, five (4.6 net) heavy oil wells, and one (1.0 net) light oil well.

In 2004, the Company closed a number of acquisitions and dispositions. At the end of the first quarter, True closed a swap of assets, effective during the fourth quarter of 2003, at a net cost of \$44,108. True exchanged non-core assets located in south east Saskatchewan for assets located in the Company's core west central Saskatchewan area. Also in the first quarter, True purchased assets in the Company's west central Saskatchewan core area for \$7,745,258. In the second quarter, the Company sold non-strategic assets in the Ear Lake Area for \$26,292. At the end of the second quarter, True purchased assets located in the Company's Smiley core area for \$341,420. In the fourth quarter of the year, complementary assets were purchased in the Company's Coleville Driver core area for \$32,500.

In 2004, True incurred facility costs in Saskatchewan to allow processing of increased natural gas volumes. In the third quarter, the Company replaced a rental compressor in the Dodsland area of

Saskatchewan with an owned unit. At Coleville Driver, True added a third compressor and a dehydrator, significantly increasing natural gas processing capacity. During the fourth quarter, at Dodsland, a new five Mmcf/d capacity gas processing facility was built with compression, dehydration and liquids extraction capabilities to redirect restricted gas from third party facilities and provide capacity for additional production.

In 2005, True intends to construct an additional five Mmcf/d gas processing facility with compression and dehydration capabilities to accommodate gas from the eastern portion of the Dodsland area. True also intends to build in 2005 a heavy oil facility capable of processing 2,000 bbls/d of crude oil in the Smiley area of Saskatchewan.

Capital Expenditures \$000s

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003	2004	2003
Lease acquisitions & retention	2,739	830	5,790	2,317
Geological & geophysical	608	481	1,828	1,050
Drilling & completion costs	11,958	4,588	30,911	12,603
Facilities & equipment	2,107	687	8,113	2,396
Exploration & development	17,412	6,586	46,642	18,366
Acquisitions	40	450	8,428	632
Head office expenditures	26	493	140	1,042
Total expenditures	17,478	7,529	55,210	20,040
Dispositions	21	-	(291)	-
Net capital expenditures	17,499	7,529	54,919	20,040

True continues to develop its land base. At December 31, 2004, True had 449,456 gross (306,524 net) undeveloped acres of land, of which 153,660 net acres are in Alberta and 152,864 net acres are in Saskatchewan. In comparison, at December 31, 2003, True had 362,493 gross (218,244 net) acres of undeveloped land.

On January 20, 2005, the Company announced that it had entered into an agreement with Meridian Energy Corporation pursuant to which the Company would make an offer to acquire all of the outstanding common shares of Meridian on the basis of, at the election of the Meridian shareholder, (a) 0.91 common shares of the Company per Meridian share; or (b) \$3.85 in cash per Meridian share; or (c) a combination thereof, provided that the maximum aggregate amount of cash payable pursuant to the offer shall be limited to \$30 million. The offer was dated February 7, 2005, and is subject to certain conditions, including the deposit of not less than 66 2/3% of the outstanding Meridian shares (on a fully diluted basis), receipt of all required regulatory approvals and other customary conditions. The offer expires on March 15, 2005, unless extended. Capital spending in 2005 will be dependent upon the outcome of the currently outstanding offer to purchase Meridian.

Ceiling Test

The Company 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. In 2004, the ceiling test was 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. In 2003, the ceiling test was performed using the requirements as set out under AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

At December 31, 2004, the Company calculated the ceiling test using prices of \$25.99/bbl for heavy oil, \$42.64/bbl for light and medium gravity oil, \$41.15/bbl for NGLs and \$6.20/mcf for natural gas. As a result, the Company has a ceiling test surplus of \$97 million before tax. At January 1, 2004 the Company calculated the ceiling test using the AcG-16 methodology using prices of \$19.98/bbl for heavy oil, \$32.57/bbl for light and medium gravity oil, \$28.81/bbl for NGLs and \$5.35/mcf for natural gas giving a ceiling test surplus of \$31 million before tax.

Finding and Development Costs

True's all-in finding, development, acquisition and disposition costs for 2004, and for the three years 2002 through 2004, including revisions and future development costs, were approximately \$8.00/boe for proved and probable reserves and approximately \$10.00/boe for proved reserves.

	Proved	Proved and probable
All in finding, development, acquisition and disposition costs, including future capital		
Capital: (\$000s)		
Exploration and development capital	46,782	46,782
Acquisition capital	8,428	8,428
Disposition capital	(291)	(291)
Total capital incurred in the year	54,919	54,919
Future capital, December 31, 2004	11,398	19,224
Future capital, January 1, 2004	1,813	5,957
Change in future capital	9,585	13,267
Total, including future capital	64,504	68,186
Reserve net additions: (mboe)		
Exploration and development reserve additions	5,670	7,710
Acquisition additions	261	341
Dispositions	-	-
Revisions	495	591
Total reserve net additions	6,426	8,642
All-in finding, development, acquisition and disposition costs (\$/boe)	\$ 10.04	\$ 7.89
Average cost for 2002, 2003 and 2004 (\$/boe)	\$ 10.19	\$ 8.34
Finding and development costs, excluding acquisitions and dispositions, including future capital		
Capital: (\$000s)		
Exploration and development capital	46,782	46,782
Change in future capital	9,585	13,267
	56,367	60,049
Reserve additions (excluding acquisitions and dispositions, including revisions): (mboe)		
Exploration and development reserve additions	5,670	7,710
Revisions	495	591
	6,165	8,301
Finding and development costs, excluding acquisitions and dispositions, including future capital (\$/boe)	\$ 9.14	\$ 7.23
Average cost for 2002, 2003 and 2004 (\$/boe)	\$ 8.64	\$ 7.16
Acquisition costs, including future capital		
Acquisition capital (\$000s)	8,428	8,428
Reserve additions for acquisitions: (mboe)	261	341
Acquisition costs, including future capital (\$/boe)	\$ 32.29	\$ 24.72
Average cost for 2002, 2003 and 2004 (\$/boe)	\$ 15.23	\$ 10.61

In comparison, in 2003, the all-in finding, development, acquisition and disposition cost, including future capital was \$12/boe for proved as well as for proved and probable reserves. The average all-in finding, development, acquisition and disposition cost for the three years 2001, 2002 and 2003 was \$13/boe for proved and \$11/boe for proved and probable reserves. Finding and development costs, excluding acquisitions and dispositions but including future capital was \$11/boe for proved and \$10/boe for proved and probable reserves in 2003. The average finding and development costs, excluding acquisitions and dispositions but including future capital for the three years 2001, 2002 and 2003 was \$10/boe for proved and \$9/boe for proved and probable reserves. The acquisition costs, including future capital in 2003 was \$19/boe for proved and \$18/boe for proved and probable reserves. For the three years 2001, 2002 and 2003 the acquisition costs, including future capital in 2003 was \$14/boe for proved reserves and \$12/boe for proved and probable reserves.

True's presentation of additional calculations of finding and development costs over required disclosure (showing all in costs and the costs of acquisitions) is provided for more comprehensive information on the Company's activities.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect True's finding and development costs related to reserves additions for that year.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the fourth quarter of 2004 was \$4.5 million, compared to \$2.9 million in 2003, approximately 2% lower per boe in 2004. For the twelve months ended December 31, 2004 the depletion, depreciation and accretion charge of \$14.6 million was 3% greater per boe than the corresponding 2003 period. Increased costs of services and in particular the cost of steel required for oil and gas tangible equipment in 2004 are contributing factors in this increase, along with the significant expenditures made for facilities in the year.

In 2005, True will also need to incur expenditures for facilities, especially in the Dodsland area of Saskatchewan. In addition, if the acquisition of Meridian is successful, depletion, depreciation and accretion charges will reflect the significantly higher cost of purchasing these assets in comparison to the cost levels incurred through primarily drilling and equipping wells.

The costs for the three and twelve month periods ending December 31, 2003 have been restated to reflect the adoption of CICA Handbook Section 3110 "Asset Retirement Obligations", with increased charges of \$22 thousand and \$36 thousand respectively, or \$0.06/boe and \$0.04/boe respectively.

Depletion, Depreciation and Accretion Costs \$000's, except where noted

	Three Months ended Dec. 31, (unaudited)		Twelve Months ended Dec. 31,	
	2004	2003*	2004	2003*
Depletion	3,187	1,866	10,059	5,037
Depreciation	1,236	1,001	4,394	3,244
Accretion	47	34	170	123
Total	4,470	2,901	14,623	8,404
Per unit (\$/ boe)	8.20	8.41	7.91	7.67

* restated to reflect changes in accounting policies

Income Taxes

Capital taxes paid by the Company are in respect of the Federal Large Corporations Tax and the Saskatchewan Capital Tax. For the three and twelve months ending December 31, 2004 True has recorded a provision for capital taxes of \$0.3 million and \$1.4 million respectively, reflecting both the growth in the balance sheet of the Company and the increased gross sales revenues from Saskatchewan based properties. For the year ended December 31, 2003, the provision for capital taxes was \$0.8 million. The total long-term liability for capital taxes is \$1.4 million at the end of 2004 compared to \$0.8 million as at the end of 2003.

The provision for future income taxes for 2004 is \$9.1 million, of which \$2.6 million has been recorded during the fourth quarter of this year. Future income tax expense for the twelve and three month periods ending December 31, 2003 have been restated by minor amounts to reflect the adoption of CICA Handbook Section 3110 "Asset Retirement Obligations". In 2003, there have been substantively enacted changes to the federal and Alberta income tax rates and to deductions for resource income, reducing the rate on resource income, providing for the deduction of Crown royalties and eliminating the resource allowance over a five-year period. For True, the expected income tax charge was reduced by the impact of an approximate 1.45% drop in tax rates, a change in valuation allowance, which was more than offset by a partnership deferral and flow-through share renunciations. Over the 2003 to 2007 period, the federal tax rate is to be reduced by seven percentage points, and the resource allowance deduction is going to be phased out, to be replaced by a deduction for Crown royalties paid. The total liability for future income taxes was \$13.2 million as at December 31, 2004 and \$4.5 million as at December 31, 2003.

At December 31, 2004, the Company had approximately \$58 million in tax pools available for deduction against future earnings.

Summary of Tax Pools (\$millions)	Estimated Balance at December 31, 2004
Canadian exploration expense	7
Canadian development expense	34
Canadian oil and gas property expense	30
Undepreciated capital cost	16
Other	2
Partnership deferral	(31)
	58

Liquidity and Capital Resources

True's net debt as at December 31, 2004 was \$22.2 million, with \$12.7 million drawn on a revolving credit facility and the balance a net working capital shortfall. True continues to target maintaining a net debt to historical cash flow ratio of below 1.3 times. At the end of 2004, the Company's ratio of net debt compared to 2004 historical cash flow was 0.7 to 1.0.

Since December 31, 2003, the terms and conditions of True's demand revolving operating credit facility with a Canadian chartered bank have been revised numerous times. True currently has a \$38.5 million facility. Amounts outstanding under the facility are now secured by a first floating charge debenture in the amount of \$150 million with a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances. The availability under the facility is subject to an interim review by April 1, 2005 and an annual review by June 30, 2005.

On February 4, 2005, the terms of the demand revolving credit facility were revised to increase the authorized borrowing amount to \$85 million subject to True acquiring a minimum of 66 2/3% of Meridian shares. Interest is payable at the lenders' prime rate, subject to adjustment depending on the debt to cash flow ratio. The availability under the facility is subject to an annual review on or before June 1, 2005. No other terms or conditions were modified.

In April 2004, True closed a bought-deal private placement of common and flow-through shares for aggregate proceeds of \$13.3 million, before expenses. In conjunction with this private placement, True committed to incur by the end of 2005 \$5.5 million of Canadian exploration expenses ("CEE"). As at December 31, 2004 \$2.1 million remains to be incurred on qualifying expenditures. The Company is confident this obligation will be met.

The Company expects to be able to fund its capital expenditure program in 2005 using cash flow from operations and available credit facilities. If cash flows are other than projected, capital expenditure levels will be adjusted to meet the targeted ratio. The Company's practice of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required. True anticipates combined net debt of True and Meridian as at March 15, 2005 will be approximately \$66.0 million, if the maximum \$30 million available under the terms of the Meridian offer is

required to be paid to the Meridian shareholders, and \$36.0 million if none if paid. Management believes the financial condition of the Company at the end of 2004 continues to be strong, based on the combination of relatively low debt levels combined with strong commodity prices in conjunction with a disciplined capital expenditure program.

At December 31, 2004, True had 62,097,979 common shares outstanding and 3,958,567 options outstanding at an average exercise price of \$1.35 per share. As at March 1, 2005 the Company has 62,164,976 common shares outstanding and 3,904,902 options outstanding at an average exercise price of \$1.46 per share.

Business Prospects and 2005 Outlook

True is optimistic about its future prospects. The Company has been successful in growing its production and land base since its formation in September 2000 and expects to continue with future growth through development of its core assets and new exploration on the Company's inventory of geological prospects. Currently, the Company's producing properties are located in west central Saskatchewan and west central Alberta. In 2005, the Company will continue to focus its exploration efforts in areas of multi-zone potential for natural gas and economically viable crude oil.

The Company anticipates that 2005 average production will be approximately 9,000 boe/d, weighted approximately 70% towards natural gas. This assumes the Company's February 7, 2005 offer to purchase all the outstanding common shares of Meridian is successful effective April 1, 2005. True believes world and domestic supply and demand factors will result in continuing strong prices for crude oil and natural gas prices around the current levels for the balance of this year. True further anticipates the US\$/ Cdn \$ exchange rate to average 0.83 during 2005.

In 2005, operating costs are expected to continue approximately at current levels of around \$6/boe, assuming no significant unusual weather conditions. The Company currently anticipates capital spending, excluding the purchase of Meridian, of approximately \$80 million during 2005 on oil and gas exploration and development activities within the core west central Saskatchewan and west central Alberta areas, including asset acquisitions.

Impact of New Accounting Pronouncements

Effective January 1, 2004, True adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost". In September 2002, the Canadian Institute of Chartered Accountants ("CICA") approved Section 3063, "Impairment of Long-Lived Assets" (S. 3063), established standards for the recognition, measurement and disclosure of the impairment of long-lived assets and applies to long-lived assets held for use. An impairment loss is recognized when the carrying value exceeds its fair value and is not recoverable. This standard is effective for fiscal years beginning on or after April 1, 2003. AcG-16, issued in September 2003, includes this section in the application of the impairment test for oil and gas companies using the full cost method of accounting. The carrying value for oil and gas properties is limited to their fair value, which is equal to estimated future cash flows from proved and probable reserves, calculated using future price forecasts and costs discounted at a risk-free rate. The former ceiling test used undiscounted cash flows determined using constant prices, reduced for general and administrative and financing costs. The adoption of this standard had no material adverse impact on the Company's financial results.

Also effective January 1, 2004 True adopted the CICA's new accounting pronouncement Accounting Guideline 13 "Hedging Relationships" (AcG-13) which is in effect for fiscal years commencing on or after July 1, 2003. This Guideline sets out certain conditions when hedge accounting may be applied; otherwise the fair values of derivative financial instruments are recorded as an asset or liability on the balance sheet. True does not currently have any hedges; hence the guideline has no current applicability.

For the fiscal year beginning January 1, 2004, True adopted the CICA's new section "Asset Retirement Obligations" (Section 3110). This new accounting pronouncement requires accrued reclamation and abandonment obligations be recognized on the balance sheet by increasing oil and gas properties offset by a corresponding liability. The asset and liability are initially measured at fair value, being the discounted future value of the liability, and then capitalized as part of the cost of the asset and subsequently amortized over the life of the asset. The liability accretes until the retirement obligation is settled. Comparative numbers for 2003 and prior periods have been restated and the impact is disclosed in Note 3 of the financial statements. The adoption of this standard does not have a material adverse impact on the Company's financial position or results of operations.

For the fiscal year beginning January 1, 2004, True revised its presentation of transportation costs in accordance with CICA Handbook Section 1100 "Generally Accepted Accounting Principles". As a result, revenue has been presented prior to transportation costs and a separate expense for transportation costs has been presented in the statements of operations and deficit. The Company has reclassified previously reported amounts to be consistent with the presentation under this new policy. Revenue and transportation costs both increased (by \$0.5 million and \$0.3 million in the fourth quarter of 2004 and 2003 respectively, and by \$1.8 million and \$0.9 million in the twelve months ended December of 2004 and 2003 respectively) as a result of this new policy. There was no impact on net income or cash flow in any quarter of 2004, nor did it impact restated net income or cash flow for any quarter of 2003.

The Company has adopted the March 19, 2004 recommendation of the Emerging Issues Committee of the CICA on flow-through shares (EIC-146), which requires the recognition of the foregone tax benefits at the time of renouncement, provided there is reasonable assurance that the expenditures will be incurred. Prior to 2004, the tax effect of the renouncement was recorded when the corresponding flow-through shares were issued. In April 2004, the Company committed to incur \$5.5 million of qualifying CEE expenditures by the end of 2005 to satisfy 2004 flow-through share agreements. In accordance with EIC-146, True will reduce its CEE income tax pool and recognize the income tax effect on related share issue costs when the expenditures are renounced to the shareholders. This renouncement was made in the first quarter of 2005, effective December 31, 2004.

True is subject to the new disclosure requirements as set out in National Instrument 51-102 ("NI51-102"), requiring financial statements to be filed on an earlier basis and enhanced disclosure for management's discussion and analysis and the annual information form.

Summary of Quarterly Information

The following table sets forth selected quarterly unaudited consolidated financial information of the Corporation for the two most recently completed financial years.

2004 – Quarter ended (\$000s, except per share amounts)	March 31	June 30	Sept. 30	Dec. 31
Gross revenues before royalties & transportation	13,342	17,377	17,760	19,469
Cash flow from operations	6,264	8,783	8,593	10,305
Per basic share	\$0.11	\$0.15	\$0.14	\$0.17
Per diluted share	\$0.11	\$0.14	\$0.14	\$0.16
Net earnings	958	2,874	2,295	2,833
Per basic share	\$0.02	\$0.05	\$0.04	\$0.05
Per diluted share	\$0.02	\$0.05	\$0.04	\$0.04
Capital expenditures, net	15,243	9,075	13,102	17,499
Average production (boe/d, 6:1)	4,155	4,972	5,130	5,927

2003 – Quarter ended * (\$000s, except per share amounts)	March 31	June 30	Sept. 30	Dec. 31
Gross revenues before royalties & transportation	10,108	7,766	9,967	10,639
Cash flow from operations	4,374	2,489	4,656	4,494
Per basic share	\$0.10	\$0.06	\$0.10	\$0.08
Per diluted share	\$0.10	\$0.05	\$0.09	\$0.08
Net earnings (loss)	1,500	1,169	2,376	(682)
Per basic share	\$0.03	\$0.03	\$0.05	\$(0.01)
Per diluted share	\$0.03	\$0.03	\$0.05	\$(0.01)
Capital expenditures, net	2,613	4,985	4,913	7,529
Average production (boe/d, 6:1)	2,569	2,376	3,303	3,749

* restated for changes in accounting policies

Selected Annual Information

Years Ended December 31, (\$000s, except per share amounts)	2004	2003*	2002*
Gross revenues before royalties & transportation	67,948	38,479	19,539
Cash flow from operations	33,945	16,012	5,912
Per basic share (\$)	0.57	0.33	0.16
Per diluted share (\$)	0.56	0.32	0.16
Net earnings	8,960	4,363	310
Per basic share (\$)	0.15	0.09	0.01
Per diluted share (\$)	0.15	0.09	0.01
Capital expenditures, net	54,919	20,040	18,802
Total assets	108,340	64,612	50,579
Total net debt - current	22,158	14,461	19,893
Long-term financial liabilities			
Capital taxes payable	1,364	836	686
Future income taxes	13,209	4,481	
Asset retirement obligations	3,951	2,702	2,211
Production (boe/d)	5,048	3,003	2,042

* restated for changes in accounting policies

Business Risks, Uncertainties and Forward Looking Statements

Statements in this document may contain forward-looking information including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward looking in nature and subject to substantial risks and uncertainties. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the readers that actual performance will be affected by a number of factors, as many may respond to changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to; the risks associated with the oil and gas industry, commodity prices and exchange rate changes. Industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. These external factors beyond the Company's control may affect the marketability of oil and natural gas produced, industry conditions including changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on this forward-looking information.

True's production and exploration activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. True is subject to the various types of business risks and uncertainties including:

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

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

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

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

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 Company's Annual Report continue to be critical in determining True's financial results.

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. Changes in these judgments and estimates could have a material impact on the financial results and financial condition. The following discussion outlines accounting policies and practices that are critical to determining True's financial results.

Reserves are critical to several accounting estimates, affecting net income through depletion, site restoration and abandonment estimates and the ceiling test calculation. Estimating reserves is very complex, requiring many judgments based on available geological, geophysical, engineering and economic data. Estimated reserves are also utilized by True's bank in determining credit facilities. Changes in these judgments could have a material impact on the estimated reserves, and subsequently the Company's financial results and financial condition.

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

affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings.

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

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

Commitments

As at December 31, 2004, True has committed to drill four wells in Alberta by the end of 2005 pursuant to various farm-in agreements with oil and gas companies. Subsequent to year-end 2004, True has further committed to drill an additional five wells. Total estimated cost to True for these commitments is \$5.9 million.

The Company has further committed to various corporate sponsorships extending to September 2006 at an estimated combined cost of up to \$85,000 (up to \$30,000 in 2005 and up to \$55,000 in 2006).

True has no off-balance sheet arrangements or variable interest entities. The Company is committed to various office leases over the next five years as follows.

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

Year	Gross Amount	Expected Recoveries	Net amount
2005	\$ 1,070,785	\$ 326,059	\$ 744,726
2006	1,015,248	260,036	755,212
2007	961,824	177,845	783,979
2008	956,687	-	956,687
2009	750,856	-	750,856

TRUE ENERGY INC.
CONSOLIDATED BALANCE SHEETS
at December 31, 2004 and 2003

	December 31, 2004	December 31, 2003 Restated –Note 3
ASSETS		
Current assets		
Accounts receivable	\$11,855,330	\$9,754,654
Deposits and prepaids	786,238	704,380
	<u>12,641,568</u>	<u>10,459,034</u>
Property, plant and equipment (notes 3 (a) & 5)	95,697,962	54,153,130
	<u>\$108,339,530</u>	<u>\$64,612,164</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$22,095,095	\$13,336,706
Bank debt (note 6)	12,704,255	11,582,860
	<u>34,799,350</u>	<u>24,919,566</u>
Capital taxes payable	1,363,746	835,878
Asset retirement obligations (notes 2(a) and 3(a))	3,950,692	2,701,573
Future income taxes (note 10)	13,209,236	4,480,568
Shareholders' equity		
Share capital (note 7)	60,228,985	46,519,371
Contributed surplus (note 9)	877,263	204,530
Deficit	<u>(6,089,742)</u>	<u>(15,049,322)</u>
	55,016,506	31,674,579
	<u>\$108,339,530</u>	<u>\$64,612,164</u>

Commitments - Note 13

See accompanying notes to consolidated financial statements.

TRUE ENERGY INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT
for the periods ended December 31, 2004 and 2003

	Three months ended Dec. 31,		Year ended Dec. 31,	
	2004	2003	2004	2003
		Restated – Note 3		Restated – Note 3
REVENUE				
Petroleum and natural gas sales	\$19,468,883	\$10,638,609	\$67,947,589	\$38,479,449
Royalties, net of Alberta royalty tax credit	5,042,260	2,612,939	17,388,728	9,516,983
	<u>14,426,623</u>	<u>8,025,670</u>	<u>50,558,861</u>	<u>28,962,466</u>
EXPENSES				
Production	2,783,518	2,349,361	10,939,293	8,150,955
Transportation (note 2(c))	534,769	320,447	1,812,552	919,017
General and administrative (note 3(b))	775,483	692,353	3,231,058	2,710,131
Interest – bank debt	114,348	121,525	413,148	776,292
Interest – other	7,228	(2,918)	114,877	(2,838)
Depletion, depreciation and accretion (notes 2(a) & 3(a))	4,469,948	2,901,603	14,623,216	8,404,367
	<u>8,685,294</u>	<u>6,382,371</u>	<u>31,134,144</u>	<u>20,957,924</u>
EARNINGS BEFORE TAXES	5,741,329	1,643,299	19,424,717	8,004,542
TAXES (note 10)				
Current income tax (recovery)	-	-	16,831	(186,611)
Capital taxes	258,342	325,745	1,369,384	784,448
Future income tax (notes 2(a), 3(a) & 10)	2,650,000	1,999,536	9,078,922	3,043,742
	<u>2,908,342</u>	<u>2,325,281</u>	<u>10,465,137</u>	<u>3,641,579</u>
NET EARNINGS (LOSS)	2,832,987	(681,982)	8,959,580	4,362,963
Deficit, beginning of period as previously stated	(8,922,729)	(14,209,795)	(14,991,672)	(19,320,423)
Change in accounting policy (notes 2(a) & 3(a))	-	(157,545)	(57,650)	(91,862)
Deficit, beginning of period as restated	<u>(8,922,729)</u>	<u>(14,367,340)</u>	<u>(15,049,322)</u>	<u>(19,412,285)</u>
Deficit, end of period	<u>\$(6,089,742)</u>	<u>\$(15,049,322)</u>	<u>\$(6,089,742)</u>	<u>\$(15,049,322)</u>
Net earnings (loss) per share (note 11)				
Basic	\$0.05	\$(0.01)	\$0.15	\$0.09
Diluted	\$0.04	\$(0.01)	\$0.15	\$0.09

See accompanying notes to the consolidated financial statements.

TRUE ENERGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
for the periods ended December 31, 2004 and 2003

	Three months ended Dec. 31,		Year ended Dec. 31,	
	2004	2003	2004	2003
		Restated – Note 3		Restated – Note 3
Cash provided by (used in):				
Operations				
Net earnings (loss)	\$2,832,987	\$(681,982)	\$8,959,580	\$4,362,963
Charges not involving cash:				
Depletion, depreciation and accretion	4,469,948	2,901,603	14,623,216	8,404,367
Stock option costs	244,395	78,492	755,657	204,530
Future income tax	2,650,000	1,999,536	9,078,922	3,043,742
Capital tax (recovery)	107,444	196,268	527,868	(3,546)
Funds from operations	10,304,774	4,493,917	33,945,243	16,012,056
Change in non-cash working capital	(2,547,155)	(2,773,019)	(163,331)	(3,358,812)
	7,757,619	1,720,898	33,781,912	12,653,244
Financing				
Issuance of common shares	275,414	2,501	14,146,829	10,081,567
Share issue costs	(20,069)	4,274	(870,394)	(774,727)
Increase (decrease) in bank debt	5,624,683	3,948,145	1,121,395	(5,612,611)
	5,880,028	3,954,920	14,397,830	3,694,229
Investing				
Additions to property, plant and equipment	(17,437,729)	(7,051,280)	(46,781,935)	(19,408,319)
Acquisition of property, plant and equipment	(39,671)	(477,412)	(8,427,512)	(631,556)
Proceeds on sale of property, plant and equipment	(21,831)	-	290,518	-
	(17,499,231)	(7,528,692)	(54,918,929)	(20,039,875)
Change in non-cash working capital	3,861,584	1,852,874	6,739,187	3,692,402
	(13,637,647)	(5,675,818)	(48,179,742)	(16,347,473)
Change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2004 and 2003

1. SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. The amounts recorded for depletion and depreciation, asset retirement obligation, ceiling test factors such as proved reserves production rates, oil and natural gas prices and future costs are estimated. Actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment and reasonable limits of materiality and within the framework of the significant policies summarized below:

a. Principles of Consolidation:

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

b. Petroleum and Natural Gas Properties:

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

c. Depletion and Depreciation:

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

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

1. SIGNIFICANT ACCOUNTING POLICIES: (continued)

d. Ceiling Test:

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

e. Joint Interests:

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

f. Asset Retirement Obligations:

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

g. Prepaid Contracts:

Advance payments received under prepaid contracts for oil and gas not delivered are deferred and are recognized as revenue when deliveries are made. Revenue is recognized on a straight-line basis by dividing the advance payment by the total contracted volumes.

h. Flow-through Common Shares:

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as future income taxes and reduce share capital at the time of renouncement.

i. Derivative Financial Instruments:

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Company does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company reviews the derivative financial instruments to determine their effectiveness as hedges, both at inception and over the term of the instruments.

1. SIGNIFICANT ACCOUNTING POLICIES:

i. Derivative Financial Instruments: (continued)

The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. If the derivatives are deemed not to qualify as hedges under Canadian accounting standards, the fair values of the derivative financial instruments are recorded as assets or liabilities on the balance sheet. Otherwise, the derivative contracts are accounted for as hedges and are not recognized on the balance sheet. Realized gains and losses on these contracts are then recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

j. Stock-based Compensation Plan:

The Company has one stock-based compensation plan, which is described in note 8. Effective January 1, 2003, compensation expense is recognized for these plans when stock options are issued to employees and extending through the vesting periods of the options. Any consideration paid by employees is credited to share capital. For stock options granted in 2002 and prior years, the Company elected to continue accounting for the related compensation expense on the intrinsic value at the grant date. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to stock options granted in 2002.

k. Revenue Recognition:

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

l. Income Taxes:

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

m. Cash and Cash Equivalents:

Cash and cash equivalents include bank balances and highly liquid temporary money market instruments with original maturities of three months or less.

2. CHANGE IN ACCOUNTING POLICY:

a. Asset Retirement Obligations:

Effective for fiscal years beginning on or after January 1, 2004, the Company adopted a new Canadian accounting standard for asset retirement obligations. Under the new standard, a liability is recognized for the future retirement obligations associated with the Company's property, plant and equipment. The fair value of the ARO is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the Company settles the obligation.

2. CHANGE IN ACCOUNTING POLICY: (continued)

b. Full Cost Accounting:

In January 2004, the Company adopted new Canadian accounting guidance for full cost accounting, which modifies how the full cost ceiling test is performed resulting in a two stage process. The first stage requires the carrying amounts of the cost centers to be tested for recoverability using undiscounted future cash flows from proved reserves and management's best estimate of forward indexed prices. When the carrying amount of a cost centre is not recoverable, the second stage of the process will determine the impairment whereby the cost centre would be written down to its fair value. The second stage requires the calculation of discounted future cash flows from proved plus probable reserves. The fair value is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows.

Under the prior method, future net revenues for ceiling test purposes were based on proved reserves and undiscounted end of period prices. Estimated future general and administrative costs and financing charges associated with the future net revenues were deducted in arriving at the "ceiling".

The Company has performed the revised ceiling test as of December 31, 2004 and there were no changes to net income, property, plant and equipment or any other reported amounts in the financial statements as a result of adopting this guideline.

The impairment test was calculated using the average price forecasts outlined in the table below.

Year	Heavy Oil (\$/bbl)	Medium / Light Oil (\$/bbl)	Natural Gas (\$/mcf)	NGL's (\$/bbl)
2005	26.34	48.39	6.48	46.02
2006	27.30	46.10	6.22	43.58
2007	27.56	43.94	6.02	41.56
2008	26.04	41.75	5.88	39.65
2009	24.32	39.32	5.90	37.45
2010	23.55	38.10	5.90	36.36
2011	23.59	38.12	5.90	36.48
2012	23.63	38.16	5.90	36.91
2013	23.59	38.62	5.99	37.50
2014	24.01	39.33	6.09	38.41
2015	23.86	39.82	6.18	39.19
2016	24.08	40.57	6.32	40.07
Remaining	25.79	43.10	6.88	44.21

c. Transportation Costs:

In 2004, the Company retroactively changed the classification of transportation costs of oil and gas deliveries to classify such costs as expenses. In prior years, it had been industry practice for companies to classify transportation charges as reductions of revenue.

2. CHANGE IN ACCOUNTING POLICY: (continued)

d. Flow-through Common Shares:

The Company has adopted Canadian standards on flow-through shares, which requires the recognition of the foregone tax benefits at the time of renouncement, provided there is reasonable assurance that the expenditures will be incurred. Prior to 2004, the tax effect of the renouncement was recorded when the corresponding flow-through shares were issued.

3. RESTATEMENT OF PRIOR PERIODS DUE TO CHANGES IN ACCOUNTING POLICIES:

The Company adopted two new accounting policies at January 1, 2004 and one new accounting policy at December 31, 2003 that required restatement of prior quarters in 2003. The following explains the impact of these restatements on the Company's previously reported 2003 results.

a. Asset Retirement Obligation:

On January 1, 2004, the company adopted the accounting policy outlined in note 2. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes. The impact of adopting this standard compared to the previous standard is:

Change in Consolidated Balance Sheet \$000s

	As at December 31, 2003
Increase in property, plant and equipment	1,552
Total assets	1,552
Future site restoration & abandonment costs	(1,222)
Asset retirement obligations	2,702
Future income tax liabilities	130
Deficit	(58)
Total liabilities and shareholders' equity	1,552

Change in Consolidated Statements of Operations and Deficit \$000s

	Year ended Dec. 31, 2003
Depletion, depreciation & site restoration	(87)
Accretion of asset retirement obligations	123
Future income taxes	(70)
Net (earnings) / loss	(34)
Per common share - basic	-
Per common share - diluted	-

3. RESTATEMENT OF PRIOR PERIODS DUE TO CHANGES IN ACCOUNTING POLICIES:

a. Asset Retirement Obligation: (continued)

The total future asset retirement obligation was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations is approximately \$7.2 million. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 21 years into the future. This amount has been discounted using credit-adjusted, risk-free interest rates of between 4.8% and 5.1%.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligations associated with the retirement of property, plant and equipment.

\$000s

	For the year ended December 31,	
	2004	2003
Asset retirement obligations, beginning of year	2,702	2,211
Liabilities incurred	983	343
Liabilities assumed on acquisitions	244	24
Liabilities released on dispositions	(148)	-
Accretion of asset retirement obligations	170	124
Asset retirement obligations, end of year	3,951	2,702

b. Stock-Based Compensation Plan:

At December 31, 2003, the Company adopted the accounting policy outlined in note 1. Under the transitional provisions of the standard, the Company is required to record compensation expense in the statement of operations and deficit for options issued on or after January 1, 2003. As a result of the implementation of this amended standard for the year ended December 31, 2003, previously reported 2003 amounts have been restated to give effect to the standard as at January 1, 2003. There is no change to previously reported net earnings for the year ended December 31, 2003, as a result of the restatement requirements. There was no impact on cash flow as a result of adopting this standard and there was no change in previously reported per share amounts.

4. ACQUISITIONS/DISPOSITIONS:

On February 2, 2004, the Company entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in the Company's west central Saskatchewan core area, effective January 1, 2004. Closing of the acquisition occurred on March 1, 2004 and the Company has accounted for this acquisition as a purchase on this date. The purchase price of \$7,745,258 was fully allocated to petroleum and natural gas properties and has an equivalent tax basis.

On December 31, 2003, the Company entered into a Letter of Intent with an arm's length third party, to exchange certain petroleum and natural gas assets located in the Company's non-core southeast central Saskatchewan area for certain petroleum and natural gas assets located in the Company's core west central Saskatchewan area. This swap was effective November 1, 2003 and closed on March 26, 2004. The net cost of this swap amounted to \$9,808 (acquisition of \$295,865 and disposition of \$286,057) and was fully allocated to petroleum and natural gas properties having an equivalent tax basis as of the closing date.

4. ACQUISITIONS/ DISPOSITIONS: (continued)

Effective October 1, 2003, the Company entered into an agreement with an arm's length third party to purchase certain petroleum and natural gas assets located in west central Alberta, specifically in the Goodwin, Greencourt, and Corbett areas (the "Acquisition"). Closing of the acquisition occurred on December 4, 2003 and the Company has accounted for this acquisition as a purchase on this date. The purchase price of \$477,412 was fully allocated to petroleum and natural gas properties and has an equivalent tax basis.

5. PROPERTY, PLANT AND EQUIPMENT:

	Cost	Accumulated depletion and depreciation	Net book value
December 31, 2004			
Petroleum and natural gas properties	\$ 170,722,799	\$ 75,565,569	\$ 95,157,230
Office furniture and equipment	1,043,094	502,362	540,732
	\$ 171,765,893	\$ 76,067,931	\$ 95,697,962
December 31, 2003 (restated)			
Petroleum and natural gas properties	\$ 114,051,038	\$ 60,408,569	\$ 53,642,469
Office furniture and equipment	902,817	392,156	510,661
	\$ 114,953,855	\$ 60,800,725	\$ 54,153,130

Unproved properties with the lesser of cost or fair value of approximately \$17,496,000 (2003 - \$11,294,000) included in property, plant and equipment have not been subject to depletion.

In 2004, the Company capitalized \$1,772,814 (2003 - \$884,073) of general and administrative expenses directly related to exploration and development activities.

6. BANK DEBT:

The Company has a \$38,500,000 demand revolving operating credit facility with a Canadian chartered bank. Interest is payable at the lenders' prime rate, subject to adjustment depending on the debt to cash flow ratio. Security is provided by a first floating charge demand debenture of \$150,000,000. 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 one eighth of one percent (0.125%) on the undrawn portion of the credit facility. The availability under the facility is subject to an interim review by April 1, 2005 and an annual review by June 30, 2005.

7. CAPITAL STOCK:

a. Authorized:

Unlimited number of voting Common Shares
 Unlimited number of non-voting First Preferred Shares

b. Issued:

	Number of Shares	Amount
Common shares:		
Balance December 31, 2002	45,134,421	\$ 38,448,124
Issued on exercise of stock options	409,999	306,567
Issued for cash on private placement	5,000,000	5,750,000
Flow-through shares issued for cash on private placement	3,500,000	4,025,000
Share issue costs, net of future income taxes of \$484,290		(290,438)
Tax effect of flow-through shares		(1,719,882)
Balance December 31, 2003	54,044,420	\$ 46,519,371
Issued on exercise of stock options	1,038,266	846,810
Issued for cash on private placement	4,457,153	7,800,018
Flow-through shares issued for cash on private placement	2,558,140	5,500,001
Transfer from contributed surplus to share capital on exercise of options		82,924
Share issue costs, net of future income taxes of \$350,255		(520,139)
Balance December 31, 2004	62,097,979	\$ 60,228,985

The Company has commitments to incur \$2.1 million of expenditures in 2005 to satisfy flow-through agreements.

c. Stock Options:

On August 31, 2000, the Board of Directors approved a stock option plan (the "Plan") for directors, officers, employees and consultants of the Company up to a maximum amount as approved by the Shareholders (6,710,000 at December 31, 2004 and 4,825,000 at December 31, 2003). The exercise price shall not be lower than the closing sale price for board lots of common shares on the trading day immediately prior to the day on which the options are granted, and an option's maximum term is 5 years. The vesting period is determined by the Board and averages 3 years.

The following table summarizes the changes in stock options outstanding:

	Options	Weighted-Average Exercise Price
Outstanding at December 31, 2002	2,529,166	\$ 0.77
Cancelled	(186,667)	0.73
Granted	1,753,500	1.05
Exercised	(409,999)	0.75
Outstanding at December 31, 2003	3,686,000	0.91
Cancelled	(35,167)	1.27
Granted	1,346,000	2.15
Exercised	(1,038,266)	0.82
Outstanding at December 31, 2004	3,958,567	\$ 1.35

7. CAPITAL STOCK: (continued)

The following table summarizes information about stock options outstanding at December 31, 2004:

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercisable Price
\$0.57 to \$0.70	675,834	2.3	\$ 0.63	544,167	\$ 0.63
\$0.73 to \$0.79	755,033	2.8	0.75	495,030	0.76
\$0.85 to \$1.00	246,700	3.0	0.94	113,366	0.92
\$1.15 to \$1.24	290,000	3.7	1.23	96,667	1.23
\$1.30 to \$2.00	1,325,000	3.9	1.49	264,991	1.41
\$2.01 to \$3.30	666,000	4.8	2.68	-	-
\$0.57 to \$3.30	3,958,567	3.5	\$ 1.35	1,514,221	\$ 0.87

8. STOCK BASED COMPENSATION:

During the year ended December 31, 2004, the Company granted 1,346,000 (2003: 1,753,500) stock options to employees, consultants and directors. The Company recorded stock option expense of \$755,657 during 2004 and \$204,530 during 2003.

For stock options granted in 2002 and prior years, the Company elected to continue accounting for the related compensation expense on the intrinsic value at the grant date. Accordingly, net income for 2002 and subsequent years remains unchanged with respect to stock options granted in 2002.

The Company continues to disclose the pro forma earnings impact of stock options granted in 2002. If the fair value method had been used for options granted in 2002, the Company's net earnings and net earnings per share for the years ended December 31, 2004 and 2003 would approximate the following pro forma amounts:

	Year ended Dec. 31,	
	2004	2003
Net Earnings:		
As reported	\$ 8,959,580	\$ 4,362,963
Pro forma	\$ 8,882,593	\$ 4,161,984
Net Earnings per Share:		
As reported	\$ 0.15	\$ 0.09
Pro forma	\$ 0.15	\$ 0.09
Diluted:		
As reported	\$ 0.15	\$ 0.09
Pro forma	\$ 0.15	\$ 0.08

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

	Year ended Dec. 31,	
	2004	2003
Assumptions:		
Risk free interest rate (%)	5.34	5.66
Expected life (years)	5.0	5.0
Expected volatility (%)	55	85
Results:		
Weighted average fair value of options granted	\$ 1.09	\$ 0.52

9. CONTRIBUTED SURPLUS:

	Year ended Dec. 31,	
	2004	2003
Balance, beginning of year	\$ 204,530	\$ -
Stock-based compensation expense	755,657	204,530
Transfer to share capital on exercise of options	(82,924)	-
Balance, end of year	\$ 877,263	\$ 204,530

10. INCOME TAXES:

The provision for income taxes differs from the expected amount calculated by applying the combined federal and provincial corporate income tax rate (2004: 41.3%, 2003: 42.75%) to earnings before income taxes. This difference results from the following items:

	2004	2003 (restated)
Expected income tax expense	\$ 8,022,408	\$ 3,437,616
Crown royalties and charges	2,810,009	1,767,302
Resource allowance	(2,870,962)	(1,654,500)
Change in valuation allowance	-	(916,434)
Change in enacted tax rates	229,099	117,884
Stock option expense	312,086	87,439
Other	593,113	17,824
Total income tax expense	\$ 9,095,753	\$ 2,857,131
Future income tax expense	\$ 9,078,922	\$ 3,043,742
Current income tax (recoveries)	16,831	(186,611)
Total income tax expense	9,095,753	2,857,131
Capital tax expense	1,369,384	784,448
Total tax expense	\$ 10,465,137	\$ 3,641,579

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

	2004	2003 (restated)
Future income tax liabilities:		
Petroleum and natural gas properties	\$ (3,640,231)	\$ (2,403,660)
Partnership deferral	(12,015,191)	(5,365,379)
Future income tax assets:		
Petroleum and natural gas properties	-	-
Future site restoration / Asset retirement obligation	1,436,483	973,377
Share issue costs	692,780	757,500
Non-capital losses	31,030	1,160,946
Attributed Canadian Royalty Income	231,839	386,658
Other	54,054	9,990
Net future income tax liability	\$ (13,209,236)	\$ (4,480,568)

During 2003, a current income tax (recovery) of \$186,611 was recorded to reflect overestimated income taxes owing by Gresham Resources Inc. and Marengo Exploration Ltd.

Included in capital tax expense of \$1,369,384 are capital taxes of \$1,363,746 that will become payable in 2005.

11. PER SHARE AMOUNTS:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year.

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted earnings per share.

In computing diluted earnings and cash flow from operations per share, 1,120,185 (2003: 950,147) shares were added to the 59,617,462 (2003: 48,335,571) weighted average number of common shares outstanding during the year for the dilutive effect of stock options. A total of 663,500 (2003: 1,021,500) options were excluded from the calculation as they were not dilutive.

12. SUPPLEMENTAL CASH FLOW INFORMATION:

	2004	2003
Cash paid:		
Interest	\$ 528,025	\$ 773,454
Taxes (net of refunds)	767,661	(152,706)

13. COMMITMENTS:

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

Year	Gross Amount	Expected Recoveries	Net amount
2005	\$ 1,070,785	\$ 326,059	\$ 744,726
2006	1,015,248	260,036	755,212
2007	961,824	177,845	783,979
2008	956,687	-	956,687
2009	750,856	-	750,856

As at December 31, 2004, the Company has committed to drill four wells in Alberta by the end of 2005 pursuant to various farm-in agreements with oil and gas companies. Subsequent to year-end 2004, the Company has further committed to drill an additional five wells. Total estimated cost to True for these commitments is \$5.9 million.

The Company has further committed to various corporate sponsorships extending to September 2006 at an estimated combined cost of up to \$85,000 (up to \$30,000 in 2005 and up to \$55,000 in 2006).

14. FINANCIAL INSTRUMENTS:

a. Credit Risk:

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

14. FINANCIAL INSTRUMENTS: (continued)

b. Fair Value of Financial Instruments:

The carrying amounts of financial instruments included in the balance sheet, other than long-term debt, approximate their fair value due to their short-term maturity. The long-term carrying value approximates fair value due to the cost of borrowing being at a floating rate.

c. Commodity Risk:

The Company seeks to reduce its exposure to commodity price risk in its business through the use of physical product arrangements, futures, and options.

On January 30, 2003, the Company entered into a natural gas commodity price swap for 3,000 gigajoules per day for the period April 1, 2003 to October 31, 2003. The contract establishes that the Company would pay the counter party the differential for any month when the AECO "C" price is established at more than CDN \$6.08 per gigajoule and that the counter party would pay the Company the differential when the AECO "C" price is established at less than CDN \$6.08 per gigajoule. For the year ended December 31, 2003, the Company recorded a reduction to gas sales of \$57,861 for this transaction.

In addition, the Company had entered into a fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of \$26.74 per barrel on 100 barrels per day for the period from May 1, 2002 to April 30, 2003. Effective October 1, 2002, the fixed price sales contract was modified in respect of the committed volumes to 50 barrels per day from October 1, 2002 to April 30, 2003. The Company had entered into another fixed price sales contract to deliver heavy oil Lloydblend (LLK) at a price of \$27.87 per barrel on 200 barrels per day for the period January 1, 2003 to June 30, 2003.

15. SUBSEQUENT EVENTS:

On January 20, 2005, the Company announced that it had entered into an agreement with Meridian Energy Corporation ("Meridian") pursuant to which the Company would make an offer to acquire all of the outstanding common shares of Meridian on the basis of, at the election of the Meridian shareholder, (a) 0.91 common shares of the Company per Meridian share; or (b) \$3.85 in cash per Meridian share; or (c) a combination thereof, provided that the maximum aggregate amount of cash payable pursuant to the offer shall be limited to \$30 million. The offer is subject to certain conditions, including the deposit of not less than 66 2/3% of the outstanding Meridian shares (on a fully diluted basis), receipt of all required regulatory approvals and other customary conditions. The offer is anticipated to expire on March 15, 2005, unless extended.

On February 4, 2005, the terms of the demand revolving credit facility were revised to increase the authorized borrowing amount to \$85,000,000, subject to True acquiring a minimum of 66 2/3% of Meridian shares. Interest is payable at the lenders' prime rate, subject to adjustment depending on the debt to cash flow ratio. The availability under the facility is subject to an annual review on or before June 1, 2005. No other terms or conditions were modified.

True Energy Inc. is a Calgary-based oil and natural gas exploration and development company. The Company's shares trade on The Toronto Stock Exchange under the symbol **TUI**. For further information, please contact:

Paul R. Baay, President & CEO (403) 750-1272

or

Joan E. Dunne, Vice President, Finance & CFO (403) 750-1262

True Energy Inc.

2300, 530 – 8th Avenue S.W.

Calgary, AB T2P 3S8

Phone (403) 266-8670

Fax: (403) 264-8163

Internet: www.trueenergy.ca