FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – MARCH 8, 2005

BAYTEX ENERGY TRUST ANNOUNCES FISCAL 2004 RESULTS

Baytex Energy Trust (TSX-BTE.UN) of Calgary, Alberta is pleased to report its operating and financial results for the three months and year ended December 31, 2004. The Trust commenced operations on September 2, 2003 as a result of the reorganization of Baytex Energy Ltd. As the Trust is considered the successor organization to Baytex Energy Ltd. for reporting purposes, comparative information is provided for the three months and year ended December 31, 2003. Pursuant to the Plan of Arrangement effecting the reorganization, certain assets were not transferred to the Trust. Accordingly, results of the corresponding periods in 2003 and 2004 are not directly comparable.

2004 Highlights

- Completed two acquisitions of natural gas and light oil assets for a total of $200 million, adding 6,300 boe/d of gas weighted production at an average cost of $31,750 per boe/d.
- Increased total reserves to 120 million boe at a finding and development cost of $10.70 per boe.
- Replaced production by 210%.
- Improved reserve life index to 9.1 years.
- Enhanced net asset value by 11% to $9.84 per unit.
- Commenced production from Seal, an impact area with long-term large resource potential.
- Expanded internal development opportunities to ensure sustainability.

	Three Months Ended			Year Ended	
FINANCIAL	**December 31, 2004**	September 30, 2004	December 31, 2003	**December 31, 2004**	December 31, 2003
($ thousands, except per unit amounts)					
Petroleum and natural gas sales	**111,521**	108,216	89,526	**420,400**	403,022
Cash flow from operations (1)	**28,114**	32,235	30,179	**136,012**	138,233
Per unit - basic	**0.44**	0.51	0.51	**2.17**	2.56
- diluted	**0.42**	0.49	0.51	**2.07**	2.49
Cash distributions paid/declared	**28,856**	28,266	25,344	**113,063**	33,382
Per unit	**0.45**	0.45	0.45	**1.80**	0.60
Net income (loss) (2)	**42,108**	(12,554)	8,490	**13,763**	35,844
Per unit - basic(2)	**0.66**	(0.20)	0.14	**0.22**	0.66
- diluted (2)	**0.65**	(0.20)	0.14	**0.21**	0.62
Exploration and development	**29,023**	20,686	22,129	**94,483**	179,232
Acquisitions – net of dispositions	**75,423**	110,316	193	**186,183**	(130,849)
Total capital expenditures	**104,446**	131,002	22,322	**280,666**	48,383
Long-term notes				**216,583**	232,562
Bank loan				**161,444**	-
Working capital deficiency (surplus)				**44,017**	(18,990)
Total net debt				**422,044**	213,572

	Three Months Ended			Year Ended	
	December 31, 2004	September 30, 2004	December 31, 2003	**December 31, 2004**	December 31, 2003
OPERATING					
Daily production					
Light oil (bbls/d)	**2,786**	1,890	1,982	**2,172**	2,273
Heavy oil (bbls/d)	**22,490**	22,083	24,400	**22,703**	23,911
Total oil (bbls/d)	**25,276**	23,973	26,382	**24,875**	26,184
Natural gas (mmcf/d)	**55.5**	50.9	58.9	**54.9**	63.0
Oil equivalent (boe/d @ 6:1)	**34,525**	32,454	36,195	**34,022**	36,686
Average prices (before hedging)					
WTI oil (US$/bbl)	**48.28**	43.88	31.18	**41.40**	31.04
Edmonton par oil ($/bbl)	**57.72**	56.32	39.56	**52.55**	43.14
BTE light oil ($/bbl)	**50.46**	52.63	37.46	**48.64**	40.01
BTE heavy oil ($/bbl)	**31.24**	34.69	24.01	**30.32**	26.68
BTE total oil ($/bbl)	**33.35**	36.11	25.04	**31.91**	27.86
BTE natural gas ($/mcf)	**6.60**	6.16	5.56	**6.46**	6.23
BTE oil equivalent ($/boe)	**35.03**	36.34	27.34	**33.75**	30.64
TRUST UNIT INFORMATION					
Unit Price					
High	**$ 14.00**	$ 13.13	$ 10.89	**$ 14.00**	$ 10.89
Low	**$ 12.60**	$ 11.65	$ 9.49	**$ 9.78**	$ 9.19
Close	**$ 12.77**	$ 12.88	$ 10.85	**$ 12.77**	$ 10.85
Units Traded (thousands)	**22,796**	13,696	30,983	**93,253**	40,976
Units Outstanding (thousands)[3]	**68,817**	65,044	64,714	**68,817**	64,714
Foreign Ownership				**31%**	35%

(1) Cash flow from operations and cash flow from operations per unit are non-GAAP terms that represent cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for prior periods have been restated due to the retroactive application of the new accounting standards for non-controlling interest (see note 3 of the consolidated financial statements).

(3) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.

Financial Review

Baytex's cash flow from operations in 2004 was negatively affected by its crude oil hedging program during the year. This program was established in the summer of 2003 with the objective of protecting cash flow in the event of a significant decline in crude oil prices. Management determined that as Baytex embarked on its first year of operations as an income trust, its top priority would be to protect cash flow for distribution purposes. In total, 15,000 bbl/d for the year was contracted with an average cap price of US$29.75. Rapidly increasing demand for crude oil from China and other developing countries in Asia, combined with the volatile geopolitical situation in the Middle East, caused oil prices to surge throughout 2004 to unprecedented levels. WTI crude averaged US$41.40 during the year, exceeding the previous high of US$37.37 set in 1980. This unforeseen strength resulted in oil hedging losses of $82.4 million during the year for Baytex, representing 38% of cash flow before hedging activities.

Continuing appreciation of the Canadian currency also negatively affected cash flow in 2004. The Canadian dollar began the year at US$0.7737 and ended the year at US$0.8308. From the beginning of 2003 to the end of 2004, the Canadian dollar had appreciated an astonishing 31%. While the associated effect on oil and gas cash flow is very significant, the impact on Baytex is partially offset because all of Baytex's long-term debt is denominated in U.S. dollars. Baytex's foreign exchange hedging program further mitigated the impact of the Canadian dollar's appreciation. During 2004, Baytex realized a gain of $4.3 million from its foreign exchange hedging contracts.

Baytex has maintained its monthly distribution at $0.15 per unit since its conversion to an income trust in September 2003. Total distributions in 2004 amounted to $113.1 million, representing a payout ratio of 83%. This high payout ratio is due to the hedging losses incurred, particularly in the fourth quarter when such losses were $27.6 million and the payout ratio reached 103%. Excluding hedging losses, the payout ratio in the fourth quarter would have been 52%. With the expiry of the 2004 hedging contracts, Baytex is projecting a significant improvement in cash flow. Under the 2005 hedging program, 8,000 bbl/d have been collared between WTI US$35.00 and US$42.55, and US$9.0 million per month have been collared between the average exchange rates of 0.8000 and 0.8218. These contracts will provide substantial downside protection to Baytex's cash flow while allowing for participation in the benefits of current commodity prices. Baytex plans to maintain its monthly distributions at $0.15 per unit in 2005 barring a significant decline in commodity prices. The lower payout ratio in 2005 should bring the cumulative payout ratio to the Trust's target range of 60% to 70%.

At year-end 2004, total net debt outstanding was $412.5 million, excluding the $9.5 million notional liabilities associated with the mark-to-market value of derivative contracts. The majority of the debt was represented by US$180 million of unsecured senior subordinated notes due in 2010. The 9.625% coupon on these notes has been swapped for LIBOR based floating rates which equated to 7.85% at year-end. These notes provide a cost efficient alternative for capital and a natural hedge on foreign exchange exposure for the Trust's U.S. dollar based revenue. The financial versatility of the Trust is also enhanced as Baytex has established its credibility as an issuer in the deep and sophisticated U.S. high yield bond market. Total senior secured revolving bank debt outstanding at year-end 2004 was $161.4 million and should represent less than one time 2005 projected cash flow. Baytex does not plan to draw on its bank facilities to fund its 2005 budgeted capital programs and cash distributions.

Operations Review

During the fourth quarter, Baytex participated in the drilling of 32 (30.1 net) wells, resulting in 25 (24.5 net) oil wells, five (3.6 net) gas wells and two (2.0 net) dry holes. For 2004, Baytex participated in the drilling of 138 (135.0 net) wells, resulting in 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) service wells and 11 (11.0 net) dry holes. The overall success rate for the year was 93.8% (93.3% net). Baytex's 2004 drilling activities placed it as the most active operator amongst energy trusts in Saskatchewan and seventh most active operator amongst energy trusts in Alberta, evidencing the business strategy and the internal development opportunities of the Trust. In addition, 29 wells were drilled by other operators through farm-in arrangements on Baytex lands during the year with Baytex retaining various working or royalty interests.

Production for the fourth quarter averaged 34,525 boe/d compared to 32,454 boe/d for the previous quarter. The increase is primarily due to the acquisition of an Alberta based private company in September 2004. In November, Baytex disposed of 370 boe/d of non-core medium gravity oil production in central Alberta for $14 million. In late December, Baytex completed the acquisition of 3,300 boe/d of natural gas and associated liquids production in the West Stoddart area of northeast British Columbia for $90 million. These two recent acquisitions significantly expand Baytex's natural gas and light oil development inventory.

In the Seal area of Alberta, Baytex completed the drilling of its first two horizontal wells in early January 2005. These wells are producing at an average rate of approximately 200 bbl/d per well. Baytex is currently drilling six non-producing vertical test wells to delineate this 20-section producing land block. In addition, four horizontal producing wells are being drilled and are expected to be on production by the end of the first quarter. Industry results in this area show that each prospective section of land could hold 2.5 million barrels of recoverable reserves with aggregate initial production of 2,000 bbl/d. The Trust's reserves report at year-end 2004 only includes 1.1 million barrels of proved reserves (1.5 million barrels of proved plus probable reserves) assigned to five wells at Seal. Baytex holds 100% working interests in approximately 100 sections of land in this area. Baytex is very encouraged by the large resource potential in this area for heavy oil development.

Capital Program Efficiency

Baytex's capital program for 2004 totaled $280 million, including $200 million spent on acquisitions of natural gas and light oil assets, $14 million of proceeds on the disposition of a medium gravity oil property and $94 million for exploration and development. Spending on exploration and development was scaled back from the original budget of $105 million due to the acquisition activities.

Under National Instrument ("NI") 51-101, finding, development and acquisition ("FD&A") costs are to be presented including the changes in future development capital ("FDC") required to bring the proved non-producing and probable reserves to production. FDC is estimated by the independent evaluators based on prevailing industry conditions as at the report date. It is indexed to inflation and applied to the FD&A calculation on an undiscounted basis. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated FDC generally will not reflect total finding and development costs related to reserves additions for that year. Furthermore, there is no provision for additional reserves that could be recognized based on the results of spending the FDC. This is particularly important in the case of heavy oil development, as NI 51-101 restricts the recognition of proved undeveloped and probable reserves to an adjacent spacing-unit basis. Success in step-out drilling could lead to the recognition of additional proved undeveloped and probable reserves. As a result, the inclusion of FDC may not fairly represent the efficiency of Baytex's current year capital program. Therefore, FD&A costs are presented herein both on an including FDC and excluding FDC basis.

Baytex is very pleased with its capital efficiency in 2004. FD&A costs for the year averaged $10.70 per boe of proved plus probable reserves, with approximately 77% of the total capital program spent on natural gas and light oil activities. Similarly, recycle ratio based on cash flow (excluding one-time hedging losses) and FD&A costs was a profitable 1.5, particularly acceptable considering 57% of cash flow was related to lower netback heavy oil production and 77% of the capital spending was related to higher cost natural gas and light oil activities.

The efficiency of Baytex's 2004 capital program is summarized as follows:

	Proved Reserves	Proved + Probable Reserves
FD&A Costs (excluding FDC) ($/boe)		
Exploration and Development	12.61	9.58
Acquisition (net of disposal)	14.40	11.37
Total	13.75	10.70
FD&A Costs (including FDC) ($/boe)		
Exploration and Development	14.98	12.19
Acquisition (net of disposal)	15.91	12.62
Total	15.58	12.46
Recycle Ratio (excluding FDC)		
Including Hedging Losses	0.7	1.0
Excluding Hedging Losses	1.2	1.5
Reserves Replacement Ratio	164%	210%

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves based on forecast prices as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2004 year-end report.

	Discounted @ 5%	Discounted @10%
Proved plus probable reserves [(1)]	$ 1,196,800,000	$ 1,019,300,000
Undeveloped land [(2)]	70,224,000	70,224,000
Net debt [(3)]	(412,531,000)	(412,531,000)
Net asset value	$ 854,493,000	$ 676,993,000
Total trust units outstanding [(4)]	68,817,072	68,817,072
Net asset value per trust unit	$12.42	$9.84

Notes:

(1) As evaluated by Sproule Associates Limited as at December 31, 2004. Net present value of future net revenue does not represent fair market value of the reserves.
(2) As evaluated by Baytex as at December 31, 2004 on 817,000 net acres of undeveloped land.
(3) Long-term debt net of working capital as at December 31, 2004, excluding $9.5 million of notional liabilities associated with the mark-to-market value of derivative contracts.
(4) Includes 66,538,252 trust units outstanding as at December 31, 2004 and 1,876,004 exchangeable shares converted at an exchange ratio of 1.21472.

Oil and Gas Reserves

Baytex announced certain of its year-end 2004 reserves information on February 10, 2005. Following is the Trust's additional summary information with regard to oil and gas reserves as at December 31, 2004. Other detailed information as required under NI 51-101 will be included in Baytex's Annual Information Form.

Reconciliation of Company Interest Reserves[(3)]
By Principal Product Type
Forecast Prices and Costs

Factors	Light and Medium Crude Oil			Heavy Oil		
	Proved [(1)] (Mbbl)	Probable [(1)] (Mbbl)	Proved + Probable [(1)] (Mbbl)	Proved [(1)] (Mbbl)	Probable [(1)] (Mbbl)	Proved + Probable [(1)] (Mbbl)
December 31, 2003	5,159	1,649	6,808	57,568	23,606	81,174
Extensions	-	-	-	5,118	1,478	6,596
Improved Recovery	23	62	85	2,879	785	3,664
Technical Revisions	121	4	125	(477)	(661)	(1,138)
Acquisitions	2,538	777	3,315	11	4	15
Dispositions	(739)	(135)	(874)	-	-	-
Economic Factors	38	74	112	(915)	(324)	(1,239)
Production	(754)	-	(754)	(8,309)	-	(8,309)
December 31, 2004	6,386	2,431	8,817	55,875	24,888	80,763

Factors	Natural Gas Liquids Proved [1] (Mbbl)	Natural Gas Liquids Probable [1] (Mbbl)	Natural Gas Liquids Proved+ Probable [1] (Mbbl)	Natural Gas Proved [1] (Mmcf)	Natural Gas Probable [1] (Mmcf)	Natural Gas Proved + Probable [1] (Mmcf)
December 31, 2003	260	95	355	81,175	24,641	105,816
Extensions	-	-	-	3,884	2,558	6,442
Improved Recovery	-	-	-	541	20	561
Technical Revisions	14	(3)	11	1,663	3,972	5,635
Acquisitions	3,449	492	3,941	46,061	13,899	59,960
Dispositions	-	-	-	(130)	(85)	(215)
Economic Factors	(10)	7	(3)	(2,108)	(904)	(3,012)
Production	(41)	-	(41)	(20,087)	-	(20,087)
December 31, 2004	3,672	591	4,263	110,999	44,101	155,100

Factors	Oil Equivalent [2] Proved [1] (MBoe)	Oil Equivalent [2] Probable [1] (MBoe)	Oil Equivalent [2] Proved + Probable [1] (MBoe)
December 31, 2003	76,510	29,457	105,967
Extensions	5,766	1,904	7,670
Improved Recovery	2,993	850	3,843
Technical Revisions	(64)	1	(63)
Acquisitions	13,674	3,590	17,264
Dispositions	(760)	(149)	(909)
Economic Factors	(1,239)	(395)	(1,634)
Production	(12,452)	-	(12,452)
December 31, 2004	84,428	35,258	119,686

Notes:
(1) Reserves information as at December 31, 2003 and 2004 is prepared in accordance with NI 51-101.
(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(3) Company interest reserves include solution gas but do not include royalty interest.

Reserves Life Index

	2005 Production Target	Reserves Life Index (RLI) Total Proved	Reserves Life Index (RLI) Proved Plus Probable
Crude Oil (bbl/d)	26,000	7.0	9.9
Natural Gas (mmcf/d)	60.0	5.1	7.1
Oil Equivalent (boe/d)	36,000	6.4	9.1

Management's Discussion and Analysis

Baytex Energy Trust (the "Trust ") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company.

Management's discussion and analysis ("MD&A"), dated March 7, 2005, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the year ended December 31, 2004 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2003. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Cash flow from operations and cash flow from operations per unit are not measures based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. They represent cash generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, other assets and deferred credits. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers it a key performance measure as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions and capital investments.

The Trust also uses certain key performance measures and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), recycle ratio and payout ratio to analyze financial and operating performance. These key performance measures and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The results of operations from the date of acquisition of the private company have been included in the consolidated financial statements. On December 22 2004, the Company acquired certain oil and natural gas interests in the West Stoddart area of northeast British Columbia. The consolidated financial statements include the results of operations from these properties from the acquisition date.

Production. Light oil production for the fourth quarter of 2004 increased by 41% to 2,786 bbl/d from 1,982 bbl/d a year earlier primarily due to the acquisition in September 2004. Heavy oil production decreased 8% to 22,490 bbl/d for the fourth quarter of 2004 compared to 24,400 bbl/d a year ago. Natural gas production decreased by 6% to 55.5 mmcf/d for the fourth quarter of 2004 compared to 58.9 mmcf/d for the same period last year. These decreases are primarily due to a lower exploration and development program in 2004 following conversion to the trust structure.

For the year ended December 31, 2004, light oil production decreased by 4% to 2,172 bbl/d from 2,273 bbl/d last year. Heavy oil production for 2004 was down 5% to 22,703 bbl/d compared to 23,911 bbl/d for the same period in 2003. Natural gas production decreased by 13% to average 54.9 mmcf/d for 2004 compared to 63.0 mmcf/d for 2003. Production for the year is not directly comparable to the previous year due to asset dispositions and transfer of assets pursuant to the Plan of Arrangement.

Revenue. Petroleum and natural gas sales increased 24% to $111.5 million for the quarter ended December 31, 2004 from $89.5 million for the same period in 2003**.** For the year, petroleum and natural gas sales increased by 4% to $420.4 million in 2004 from $403.0 million a year earlier.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2004 were 63 bbl/d higher (three months ended December 31, 2003 – 606 bbl/d lower) than the production for the period due to inventory in transit under the Frontier supply agreement. The corresponding number for the year ended December 31, 2004 was an increase of 5 bbl/d (year ended December 31, 2003 – decrease of 650 bbl/d).

	Three Months ended December 31			
	2004		2003	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil	**12,931**	**50.46**	6,830	37.46
Heavy oil	**64,881**	**31.24**	52,559	24.01
Derivative contracts loss	**(27,570)**	**(11.83)**	(6,918)	(2.92)
Total oil revenue	**50,242**	**21.55**	52,471	22.13
Natural gas revenue (mcf)	**33,709**	**6.60**	30,137	5.56
Total revenue (boe @ 6:1)	**83,951**	**26.38**	82,608	25.23

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/mcf.

Revenue from light oil for the fourth quarter of 2004 increased 89% from the same period a year ago due to a 41% increase in production and a 35% increase in wellhead prices. Revenue from heavy oil increased 23% as an 8% decrease in production was offset by a 30% increase in wellhead prices. Revenue from natural gas increased 12% as the 19% increase in wellhead prices was offset by a 6% decrease in production.

	Year Ended December 31			
	2004		2003	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil	**38,673**	**48.64**	33,197	40.01
Heavy oil	**252,016**	**30.32**	226,482	26.68
Derivative contracts loss	**(78,124)**	**(8.58)**	(33,777)	(3.62)
Total oil revenue	**212,565**	**23.34**	225,902	24.24
Natural gas revenue (mcf)	**129,711**	**6.46**	143,343	6.23
Total revenue (boe @ 6:1)	**342,276**	**27.48**	369,245	28.07

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/mcf.

For the year ended December 31, 2004, light oil revenue increased 16% from the same period last year due to a 22% increase in wellhead prices and a 4% decrease in production. Revenue from heavy oil increased 11% due to a 14% increase in wellhead prices and a 5% decrease in production. Revenue from natural gas decreased 10% as production decreased 13% and wellhead prices increased 4% compared to 2003.

Royalties. Total royalties increased to $17.4 million for the fourth quarter of 2004 from $13.5 million in 2003. Total royalties for the fourth quarter of 2004 were 15.6% of sales compared to 15.1% of sales for the same period in 2003. For the fourth quarter of 2004, royalties were 15.9% of sales for light oil, 13.5% for heavy oil and 19.5% for natural gas. These rates compared to 14.5%, 11.2% and 21.9%, respectively, for the same period last year.

For the year ended December 31, 2004, royalties decreased to $66.0 million from $67.2 million for the same period last year. Total royalties for 2004 were 15.7% of sales, a decrease from 16.7% of sales for 2003. For 2004, royalties were 14.1% of sales for light oil, 13.3% for heavy oil and 20.9% for natural gas. These rates compared to 17.4%, 13.0% and 22.3%, respectively, for 2003.

Operating Expenses. Operating expenses for the fourth quarter of 2004 increased to $24.3 million from $22.1 million in the corresponding quarter last year. Operating expenses were $7.63 per boe for the fourth quarter of 2004 compared to $6.74 per boe for the fourth quarter of 2003. For the fourth quarter of 2004, operating expenses were $8.57 per barrel of light oil, $8.61 per barrel of heavy oil and $0.83 per mcf of natural gas. The operating expenses 2003 were $10.43, $7.44 and $0.72, respectively.

Operating expenses for the year 2004 increased to $89.1 million from $86.0 million in 2003. Operating expenses were $7.15 per boe in 2004 compared to $6.54 per boe for the prior year. In 2004, operating expenses were $9.51 per barrel of light oil, $7.83 per barrel of heavy oil and $0.82 per mcf of natural gas versus $8.32, $7.34 and $0.73, respectively, for 2003. Increases in per boe operating expenses are due to lower production in 2004 combined with inflation in costs for oilfield services during a period of record high industry activities.

Transportation Expenses. Transportation expenses for the fourth quarter of 2004 were $4.6 million compared to $4.7 million for the fourth quarter of 2003. These expenses were $1.43 per boe for the fourth quarter of 2004 compared to $1.45 for the same period in 2003. Transportation expenses were $1.58 per barrel of oil and $0.17 per mcf of natural gas. The corresponding amounts for 2003 were $1.57 and $0.19, respectively.

Transportation expenses for the year ended December 31, 2004 were $18.7 million compared to $17.8 million for 2003. These expenses were $1.50 per boe in 2004 compared to $1.36 in 2003. Transportation expenses were $1.66 per barrel of oil and $0.18 per mcf of natural gas in 2004, and $1.50 per barrel of oil and $0.17 per mcf of natural gas in 2003.

General and Administrative Expenses. General and administrative expenses increased to $4.1 million in the fourth quarter of 2004 from $3.6 million one year ago. On a per sales unit basis, these expenses were $1.28 per boe for the fourth quarter of 2004 compared to $1.21 per boe for 2003. In accordance with our full cost accounting policy, no expenses were capitalized in either the fourth quarter of 2003 or 2004.

General and administrative expenses for the year were $15.2 million in 2004 compared to $8.9 million for the prior year. On a per sales unit basis, these expenses were $1.22 per boe in 2004 and $0.71 per boe in 2003. In accordance with our full cost accounting policy, $4.4 million of expenses were capitalized in 2003, while no expenses have been capitalized in 2004. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation Expense. Compensation expense related to the Trust’s unit rights incentive plan was $1.6 million for the fourth quarter of 2004 compared to $0.2 million in the fourth quarter of 2003.

For the year ended December 31, 2004, compensation expense was $7.7 million compared to $0.7 million for 2003. Compensation expense on the Trust’s unit rights incentive plan has been determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The compensation expense for 2003 also includes $0.5 million based on the fair value of the stock options outstanding prior to the Plan of Arrangement.

Interest Expenses. Interest expense increased to $6.4 million for the fourth quarter of 2004 from $5.2 million for the same quarter last year. The increase is due to interest incurred on amounts drawn on the Trust’s credit facilities in the fourth quarter of 2004.

In 2004, interest expense was $19.4 million for the year compared to $23.5 million last year. The decrease in total interest expense is due to the redemption of the Company's senior secured notes in May 2003 and the stronger Canadian currency as interest on the long-term notes is denominated in U.S. dollars.

Foreign Exchange. The foreign exchange gain in the fourth quarter of 2004 was $10.9 million compared to a gain of $10.4 million in the prior year. The gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.8308 at December 31, 2004 compared to 0.7912 at September 30, 2004. The 2003 gain is based on translation at 0.7737 at December 31, 2003 compared to 0.7405 at September 30, 2003.

The foreign exchange gain for 2004 was $16.0 million compared to a gain of $52.1 million in the prior year. The 2004 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002.

Depletion, Depreciation and Accretion. The provision for depletion, depreciation and accretion was $41.5 million for the fourth quarter of 2004 compared to $42.6 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $13.04 per boe compared to $12.79 per boe for the same quarter in 2003.

Depletion, depreciation and accretion increased to $160.8 million for 2004 compared to $123.1 million for last year. On a sales-unit basis, the provision for the current year was $12.91 per boe compared to $9.36 per boe for a year earlier due to revisions in proved reserves under the new standards of disclosure for oil and gas activities, NI 51-101.

Income Taxes. Current tax expenses were $1.9 million for the fourth quarter of 2004 compared to $3.5 million for the same quarter a year ago. The current tax expense is comprised of $1.6 million of Saskatchewan Capital Tax and $0.3 million of Large Corporation Tax compared to $2.7 million and $0.8 million, respectively, in the corresponding period in 2003.

Current tax expenses were $9.0 million for 2004 compared to $9.7 million for last year. The current tax expense is comprised of $7.0 million of Saskatchewan Capital Tax and $2.0 million of Large Corporation Tax compared to $8.0 million and $1.7 million, respectively, in 2003.

Net Income Net income for the fourth quarter of 2004 was $42.1 million compared to $8.5 million for the fourth quarter of 2003. Net income for the year ended December 31, 2004 was $13.8 million compared to $35.8 million for 2003. The increased petroleum and natural gas sales realized through higher wellhead prices in 2004 were offset by increased charges for depletion, depreciation and accretion, a lower foreign exchange gain and a higher realized loss on financial derivatives.

Liquidity and Capital Resources. At December 31, 2004, total net debt (including working capital) was $422.0 million compared to $213.6 million at December 31, 2003. The $422.0 million net debt included $9.5 million of notional liabilities based on the mark-to-market value of derivative contracts as at December 31, 2004. At the end of December 2004, $161.4 million were outstanding under total bank credit facilities of $250.0 million.

Capital Expenditures. Exploration and development expenditures decreased to $94.5 million for 2004 compared to $179.2 million last year. The lower capital expenditures reflect a different business plan since the conversion to an income trust. For the year ended December 31, 2004, the Trust participated in the drilling of 138 (135.0 net) wells, resulting in 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) stratigraphic test wells and 11 (11.0 net) dry holes compared to prior year activities of 266 (243.4 net) wells, including 173 (158.9 net) oil wells, 67 (61.4 net) gas wells, seven (5.1 net) service wells and 19 (18.0 net) dry holes. On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta for $109 million plus adjustments.

Effective December 22, 2004, the Company acquired oil and natural gas interests in the West Stoddart area of northeast British Columbia for $90 million plus adjustments.

	Year Ended December 31	
($ thousands)	2004	2003
Land	**8,744**	14,138
Seismic	**1,283**	5,436
Drilling and completion	**55,322**	110,892
Equipment	**25,982**	42,365
Other	**3,152**	6,401
Total exploration and development	**94,483**	179,232
Corporate acquisition	**111,042**	-
Property acquisitions	**89,582**	6,644
Property dispositions	**(14,441)**	(137,493)
Total capital expenditures	**280,666**	48,383

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Conference Call

Baytex will host a conference call and question and answer session at 2:00 p.m. MT (4:00 p.m. ET) on Tuesday, March 8, 2005 to discuss its 2004 year-end results. The conference call will be hosted by Raymond Chan, President and Chief Executive Officer and Dan Belot, Vice-President, Finance and Chief Financial Officer. Interested parties are invited to participate by calling toll-free across North America at 1-888-793-1753. A recorded playback of the call will be available from March 8 until March 22, 2005 at 1-800-558-5253 or 416-626-4100 within the Toronto area, entering the reservation number 21230684. The conference call will also be archived on Baytex's website at www.baytex.ab.ca.

Forward-Looking Statements

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to Management's approach to operations and Baytex's production, cash flow, capital programs, debt levels and cash distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in Baytex's areas of operations; and other factors, many of which are beyond the control of Baytex. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

The consolidated financial statements for the periods ended December 31, 2004 and 2003 are attached.

For further information, please contact:

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Baytex Energy Trust
Consolidated Balance Sheets
(thousands) (Unaudited)

	December 31, 2004	December 31, 2003 (restated –note 3)
Assets		
Current assets		
Cash and short-term investments	**$ -**	$ 53,731
Accounts receivable	**41,154**	48,608
Crude oil inventory	**7,299**	5,900
	48,453	108,239
Deferred charges and other assets	**6,491**	7,764
Petroleum and natural gas properties	**1,009,933**	866,637
Goodwill (note 4)	**39,259**	-
	$ 1,104,136	$ 982,640
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 72,976**	$ 80,126
Distributions payable to unitholders	**9,981**	9,123
Bank loan	**161,444**	-
Financial derivative contracts (note 11)	**9,513**	-
	253,914	89,249
Long-term debt (note 5)	**216,583**	232,562
Asset retirement obligations (note 6)	**73,297**	55,996
Future income taxes	**164,909**	170,952
	708,703	548,759
Non-controlling interest (notes 3 and 9)	**12,962**	25,705
Unitholders' Equity		
Unitholders' capital (note 8)	**515,728**	449,403
Contributed surplus	**7,494**	224
Accumulated distributions	**(146,445)**	(33,382)
Accumulated income (deficit)	**5,694**	(8,069)
	382,471	408,176
	$ 1,104,136	$ 982,640

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Operations and Accumulated Income (Deficit)
(thousands, except per unit data) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
Revenue		(restated –note 3)		(restated –note 3)
Petroleum and natural gas sales	**$ 111,521**	$ 89,526	**$ 420,400**	$ 403,022
Royalties	**(17,392)**	(13,498)	**(65,988)**	(67,175)
Realized loss on financial derivatives	**(27,570)**	(6,918)	**(78,124)**	(33,777)
Unrealized gain on financial derivatives	**40,585**	-	**597**	-
	107,144	69,110	**276,885**	302,070
Expenses				
Operating	**24,293**	22,066	**89,078**	86,034
Transportation (note 3)	**4,550**	4,739	**18,714**	17,841
General and administrative	**4,069**	3,570	**15,243**	8,927
Unit-based compensation (note 10)	**1,587**	224	**7,736**	739
Interest (note 5)	**6,448**	5,173	**19,412**	23,548
Costs on redemption of notes	**-**	-	**-**	44,771
Foreign exchange gain	**(10,851)**	(10,437)	**(15,979)**	(52,101)
Depletion, depreciation and accretion	**41,517**	42,580	**160,808**	123,137
Reorganization costs	**-**	209	**-**	18,851
	71,613	68,124	**295,012**	271,747
Income (loss) before income taxes and non-controlling interest	**35,531**	986	**(18,127)**	30,323
Income taxes (recovery)				
Current expense	**1,850**	3,450	**9,000**	9,663
Future recovery (note 7)	**(9,621)**	(11,473)	**(41,237)**	(14,516)
	(7,771)	(8,023)	**(32,237)**	(4,853)
Income before non-controlling interest	**43,302**	9,009	**14,110**	35,176
Non-controlling interest (notes 3 and 9)	**(1,194)**	(519)	**(347)**	668
Net income	**$ 42,108**	$ 8,490	**13,763**	35,844
Accumulated deficit, beginning of year, as previously reported			**(351)**	(38,489)
Accounting policy change for non-controlling interest (note 3)			**529**	-
Accounting policy change for asset retirement obligations (note 3)			**(8,247)**	(5,424)
Accumulated deficit, beginning of year, as restated			**(8,069)**	(43,913)
Accumulated income (deficit), end of year			**$ 5,694**	$ (8,069)
Net income per trust unit				
Basic	**$ 0.66**	$ 0.14	**$ 0.22**	$ 0.66
Diluted	**$ 0.65**	$ 0.14	**$ 0.21**	$ 0.62
Weighted average units				
Basic	**63,385**	59,382	**62,574**	53,995
Diluted	**66,344**	59,644	**65,682**	56,520

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
(thousands) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2004	2003	**2004**	2003
Cash provided by (used in):		(restated –note 3)		(restated –note 3)
OPERATING ACTIVITIES				
Net income	**$ 42,108**	$ 8,490	**$ 13,763**	$ 35,844
Items not affecting cash:				
Unit-based compensation (note 8)	**1,587**	224	**7,736**	739
Amortization of deferred charges	**2,795**	276	**11,171**	1,027
Costs on redemption of notes (note 5)	**-**	-	**-**	44,771
Unrealized foreign exchange gain	**(10,851)**	(10,437)	**(15,979)**	(52,101)
Depletion, depreciation and accretion	**41,517**	42,580	**160,808**	123,137
Unrealized gain on financial derivatives (note 10)	**(40,585)**	-	**(597)**	-
Future income tax recovery	**(9,621)**	(11,473)	**(41,237)**	(14,516)
Non-controlling interest (notes 3 and 9)	**1,194**	519	**347**	(668)
Cash flow from operations	**28,144**	30,179	**136,012**	138,233
Change in non-cash working capital	**5,342**	(5,098)	**3,589**	(8,060)
Site restoration and reclamation expenditures	**(1,189)**	(261)	**(2,739)**	(880)
Decrease in deferred charges and other assets	**53**	53	**212**	211
Decrease in deferred credits	**-**	-	**-**	(2,213)
	32,350	24,873	**137,074**	127,291
FINANCING ACTIVITIES				
Redemption of senior secured notes (note 5)	**-**	-	**-**	(89,950)
Increase in bank loan	**47,601**	-	**161,444**	-
Increase in deferred charges and other assets	**-**	(39)	**-**	(7,425)
Payments of distributions	**(28,169)**	(24,259)	**(112,074)**	(24,259)
Issue of trust units	**44,295**	61,525	**44,505**	61,525
Issue of common shares	**-**	-	**-**	37,049
	63,727	37,227	**93,875**	(23,060)
INVESTING ACTIVITIES				
Petroleum and natural gas property expenditures	**(118,605)**	(22,540)	**(184,065)**	(185,876)
Corporate acquisition (note 4)	**-**	-	**(111,042)**	-
Disposal of petroleum and natural gas properties	**14,159**	218	**14,441**	137,493
Change in non-cash working capital	**6,586**	(9,254)	**(4,014)**	(6,215)
	(97,860)	(31,576)	**(284,680)**	(54,598)
Change in cash and short-term investments	**(1,783)**	30,524	**(53,731)**	49,633
Cash and short-term investments, beginning of period	**1,783**	23,207	**53,731**	4,098
Cash and short-term investments, end of period	**$ -**	$ 53,731	**$ -**	$ 53,731

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements (unaudited)
Three Months and Year Ended December 31, 2004 and 2003
(all tabular amounts in thousands, except per unit amounts)

1. Basis of Presentation

Baytex Energy Trust (the “Trust”) was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the “Company”) and Crew Energy Inc. (“Crew”). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. Accounting Policies

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2003, except as described below and in note 3. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust’s annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust’s consolidated financial statements and notes thereto for the year ended December 31, 2003.

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business for accounting purposes. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the reporting entity. If the fair value of the Trust is less that the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

3. Changes in Accounting Policy

Unit-Based Compensation

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Previously reported amounts for 2003 have been restated to give effect to the standard as at January 1, 2003. Compensation expense of $0.52 million was recorded for the year ended December 31, 2003 (three months ended December 31, 2003 – nil) for all stock options granted by the Company since January 1, 2003, with a corresponding amount recorded as contributed surplus (see note 10).

Full Cost Accounting

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting – Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the carrying amount of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust:

	2004	2005	2006	2007	2008
WTI ($U.S./bbl)	29.63	26.80	25.76	26.14	26.53
AECO ($Cdn/mcf)	6.03	5.36	4.80	4.91	4.98

Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the CICA Section 3110, “Asset Retirement Obligations”. This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by $2.8 million, net of future income tax of $0.8 million (three months ended December 31, 2003 – $0.3 million, net of future income tax of $0.3 million). At December 31, 2003 the asset retirement obligations balance increased by $32.5 million to $56.0 million, the petroleum and natural gas assets balance increased by $19.2 million to $862.4 million and the future tax liability decreased by $5.0 million to $169.3 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow as a result of adopting this policy (see note 6).

Financial Derivative Contracts

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC 128) also became effective. EIC 128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

As of January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance was recognized in income over the term of the previously designated hedged item. At December 31, 2004 the mark-to-market value of these non-hedging financial derivatives was zero as all gains and losses have been realized and recorded in the consolidated statement of operations over the course of the year. At December 31, 2004, the Trust recorded a liability of $9.5 million on the mark-to-market value of the non-hedging financial derivatives entered into in 2004 for calendar 2005 (note 11).

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by $18.7 million (2003 – $17.8 million) and for the three months ended December 31, 2004 increased by $4.6 million (2003 – $4.7 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

Non-controlling interest

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, “Exchangeable Securities Issued by Subsidiaries of Income Trusts” (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

As a result of the adoption of EIC 151, net income was reduced for the year ended December 31, 2004 by $0.35 million for the non- controlling interest's share of income and was increased for the year ended December 31, 2003 by $0.67 million for the non- controlling interest's share of the loss from the date of the Arrangement. Net income for the three months ended December 31, 2004 was reduced by $1.2 million (three months ended December 31, 2004 - $0.5 million). As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where Unitholders’ capital was increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a

$15.0 million increase in petroleum and natural gas properties (December 2003 - $4.3 million), a $5.7 million increase in future income taxes (December 2003 - $1.6 million) and a $10.9 million increase in unitholders' capital (December 2003 - $2.8 million).

4. Corporate Acquisition

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The acquisition was financed with the Company's credit facilities. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. The Company has not yet completed its final valuation of the assets acquired and liabilities assumed and, therefore, the purchase price allocation may be subject to change. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	$ 109,777
Goodwill	39,259
Working capital	1,447
Capital lease obligation	(777)
Asset retirement obligation	(8,435)
Future income taxes	(30,229)
Total net assets acquired	$ 111,042
Financed by:	
Cash	$ 110,822
Costs associated with acquisition	220
Total purchase price	$ 111,042

Goodwill of $39.3 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. Long-term Debt

	December 31, 2004	December 31, 2003
10.5% senior subordinated notes (US$247,000)	**$ 297**	$ 319
9.625% senior subordinated notes (US$179,699,000)	**216,286**	232,243
	$ 216,583	$ 232,562

Interest Expense

The Trust incurred interest expense on its outstanding debt as follows:

	Three Months Ended December 31		**Year Ended December 31**	
	2004	2003	**2004**	2003
Credit facility charges	**$ 1,798**	$ 114	**$ 2,256**	$ 675
Amortization of deferred charge	**267**	276	**1,060**	1,027
Long-term debt interest	**4,383**	4,783	**16,096**	21,846
	$ 6,448	$ 5,173	**$ 19,412**	$ 23,548

6. Asset Retirement Obligations

	December 31, 2004	December 31, 2003
Balance, beginning of year	**$ 55,996**	$ 52,244
Liabilities incurred	**4,623**	4,010
Liabilities settled	**(2,739)**	(880)
Acquisition of liabilities	**12,797**	-
Disposition of liabilities	**(1,722)**	(3,335)
Accretion	**4,342**	3,957
Balance, end of year	**$ 73,297**	$ 55,996

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

7. Income Taxes

Future income tax expense for the year ended December, 2004 included a non-recurring adjustment to future income taxes resulting from a decrease to the Alberta corporate income tax rate from 12.5 percent to 11.5 percent.

8. Unitholders' Capital

Trust Units

The Trust is authorized to issue an unlimited number of trust units.

Trust Units	**# of units**	**Amount**
Balance December 31, 2003	60,821	$ 449,403
Issued on conversion of exchangeable shares	1,994	21,222
Issued on exercise of trust unit rights	113	1,472
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	$ 515,728

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders can elect to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a 5% discount from the weighted average closing price of the trust units on the Toronto Stock Exchange for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market prices.

9. Non-Controlling Interest

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2004 was 1.21472 trust units per exchangeable share (2003 -

1.04530 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase or decrease to the non-controlling interest on the balance sheet.

Non-controlling Interest	**Number of Exchangeable Shares**	**Amount**
Issued September 2, 2003 pursuant to Plan of Arrangement	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,134)
Non-controlling interest in net loss	-	(668)
Balance December 31, 2003	3,725	25,705
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income	-	347
Balance December 31, 2004	1,876	$ 12,962

10. Trust Unit Rights

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan (the "Plan") to replace the stock option plan of the Company. A total of 5,800,000 trust unit rights are reserved for issue under the Plan. Trust unit rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future oil and natural gas prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in earning over the vesting period of the plan. Compensation expense for the unit rights for the year ended December 31, 2004 was $7.7 million (three months ended December 31, 2004 - $1.6 million).

The number of unit rights issued and exercise prices are detailed below:

	# of Rights	Weighted average exercise price (1)
Balance December 31, 2003	2,855	$ 10.15
Granted	1,297	$ 11.77
Exercised	(113)	$ 8.87
Cancelled	(502)	$ 9.54
Balance December 31, 2004	3,537	$ 9.60

(1) Exercise price reflects grant price less reduction in exercise price as discussed above.

The adoption of the amendments related to accounting for unit-based compensation (note 3) also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. For the year ended December 31, 2003, compensation expense related to the stock options granted by the Company since January 1, 2003 was $0.52 million. Compensation expense for options granted during 2003 was based on the estimated fair value at the time of the grant and the expense was recognized over the vesting period of the options.

11. Financial Derivative Contracts

At December 31, 2004, the Trust had financial derivative contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2005	3,000 bbl/d	US$35.00 – $42.40	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.50	WTI
Price collar	Calendar 2005	1,000 bbl/d	US$35.00 – $42.70	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.75	WTI

	Period	Principal	Rate
Interest rate swap			
	November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

As discussed in note 3, under the new guideline for hedge accounting, the Trust's financial derivative contracts for oil and foreign currency do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. At January 1, 2004, the fair value of all outstanding financial derivative contracts that were not considered accounting hedges was recorded on the consolidated balance sheet with an offsetting deferred credit of $10.1 million. The deferred credit balance has been recognized into income during the year ended December 31, 2004. The mark-to-market value of the outstanding non-hedging financial derivatives is recorded as a liability of $9.5 million at December 31, 2004. The change in the mark-to-market value of these financial derivative contracts from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $0.6 million in the consolidated statement of operations.

12. Supplemental Cash Flow Information

	Three Months Ended December 31		**Year Ended December 31**	
	2004	2003	**2004**	2003
Interest paid	**1,799**	2,161	**21,096**	24,449
Income taxes paid	**2,408**	1,756	**17,485**	12,557

13. Reclassification

Certain comparative figures have been reclassified to conform to the current periods' presentation.

14. Subsequent Event

In January 2005, the Company entered into agreements to collar the exchange rate on US$9 million per month at average $CDN/$US rates between $1.2168 and $1.2500.