BAYTEX

ENERGY TRUST

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA –MARCH 12, 2008

BAYTEX ENERGY TRUST ANNOUNCES RECORD PRODUCTION AND CASH FLOW FOR 2007

Baytex Energy Trust (TSX: BTE.UN; NYSE: BTE) is pleased to announce its operating and financial results for the three months and year ended December 31, 2007.

Highlights

- Record cash flow of $98.7 million ($1.10 per diluted unit) for the fourth quarter of 2007, 32% higher than the previous record set in Q3/07;
- Record cash flow of $286 million ($3.34 per diluted unit) for 2007, 4% higher than the previous record set in 2006;
- Record average quarterly production of 39,304 boe/d for Q4/07 and annual production of 36,222 boe/d for 2007;
- Maintained monthly distributions at $0.18 per unit, with conservative and sustainable payout ratios of 38% after DRIP (46% before DRIP) for Q4/07 and 51% after DRIP (61% before DRIP) for 2007;
- Increased proved plus probable reserves by 16% to 168.1 million boe at year end 2007;
- Replaced 123% of production through an exploration and development capital program equal to 52% of cash flow and 274% of production through an overall capital program (including acquisitions) equal to 138% of cash flow;
- Achieved finding, development and acquisition ("FD&A") costs of $10.90/boe (one-year) and $7.83/boe (three-year);
- Realized recycle ratios of 2.4 (one-year) and 3.4 (three-year); and
- Improved financial position with year-end total monetary debt of $444 million or 1.3 times annualized second half 2007 cash flow.

FINANCIAL	Three Months Ended			Year Ended	
($ thousands, except per unit amounts)	**December 31, 2007**	September 30, 2007	December 31, 2006	**December 31, 2007**	December 31, 2006
Petroleum and natural gas sales	**197,348**	164,228	134,541	**618,927**	556,689
Cash flow from operations (1)	**98,667**	74,957	63,519	**286,030**	274,662
Per unit – basic	**1.17**	0.90	0.85	**3.57**	3.77
- diluted	**1.10**	0.84	0.79	**3.34**	3.45
Cash distributions	**37,314**	38,746	34,516	**145,927**	143,072
Per unit	**0.54**	0.54	0.54	**2.16**	2.16
Net Income	**41,353**	36,674	19,988	**132,860**	147,069
Per unit – basic	**0.49**	0.44	0.27	**1.66**	2.02
- diluted	**0.48**	0.43	0.26	**1.60**	1.91
Exploration and development	**34,349**	43,533	24,343	**148,719**	132,381
Acquisitions – net of dispositions	**5,064**	752	7	**245,427**	702
Total capital expenditures	**39,413**	44,285	24,350	**394,146**	133,083
Long-term notes	**177,805**	179,280	209,691	**177,805**	209,691
Bank loan	**241,748**	259,328	127,495	**241,748**	127,495
Convertible debentures	**16,150**	16,531	18,906	**16,150**	18,906
Working capital deficiency	**8,362**	12,189	10,718	**8,362**	10,718
Total monetary debt	**444,065**	467,328	366,810	**444,065**	366,810

	Three Months Ended			Year Ended	
	December 31, 2007	September 30, 2007	December 31, 2006	**December 31, 2007**	December 31, 2006
OPERATING					
Daily production					
Light oil & NGL (bbl/d)	**8,123**	6,556	3,643	**5,483**	3,735
Heavy oil (bbl/d)	**22,196**	22,593	22,416	**22,092**	21,325
Total oil (bbl/d)	**30,319**	29,149	26,059	**27,575**	25,060
Natural gas (MMcf/d)	**53.9**	53.7	51.4	**51.9**	55.4
Oil equivalent (boe/d @ 6:1)	**39,304**	38,094	34,631	**36,222**	34,292
Average prices (before hedging)					
WTI oil (US$/bbl)	**90.68**	75.38	60.21	**72.31**	66.22
Edmonton par oil ($/bbl)	**86.41**	80.24	64.49	**76.35**	72.77
BTE light oil & NGL ($/bbl)	**74.77**	67.82	48.62	**65.53**	53.84
BTE heavy oil ($/bbl)	**50.13**	45.89	41.15	**44.28**	43.57
BTE total oil ($/bbl)	**56.37**	50.85	42.19	**48.45**	45.10
BTE natural gas ($/Mcf)	**6.31**	5.80	7.03	**6.61**	7.13
BTE oil equivalent ($/boe)	**52.32**	47.06	42.19	**46.38**	44.48
TRUST UNIT INFORMATION					
TSX (C$)					
Unit price					
High	**$20.65**	$21.45	$25.82	**$22.92**	$28.66
Low	**$18.08**	$16.68	$18.95	**$16.68**	$16.81
Close	**$19.00**	$20.13	$22.28	**$19.00**	$22.28
Volume traded (thousands)	**17,426**	26,365	31,901	**86,185**	102,652
NYSE (US$) (2)					
Unit price					
High	**$21.74**	$21.03	$22.84	**$21.74**	$25.87
Low	**$18.19**	$15.51	$16.63	**$15.51**	$16.63
Close	**$19.11**	$20.33	$18.96	**$19.11**	$18.96
Volume traded (thousands)	**5,433**	5,315	8,580	**18,063**	21,496
Units outstanding (thousands) (3)	**87,169**	86,478	77,498	**87,169**	77,498

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items (see reconciliation under MD&A). 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) Data reflects the periods since commencement of trading on March 27, 2006 on the NYSE.

(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.

Operations Review

Capital expenditures for exploration and development activities totaled $34.3 million for the fourth quarter of 2007. During this quarter, Baytex participated in the drilling of 16 (12.2 net) wells, resulting in 11 (9.9 net) oil wells, three (0.3 net) gas wells, one (1.0 net) service well and one (1.0 net) dry hole for a 94% (91.9% net) success rate. In addition, two wells were drilled by other operators on farm-outs from Baytex, with Baytex retaining overriding royalty interests.

Production averaged 39,304 boe/d during the fourth quarter compared to 38,094 for the third quarter of this year. The fourth quarter volume includes 460 boe/d of under-accrued production from the previous quarter. The average production for the second half of 2007, reflecting the acquisition of the assets at Pembina and Lindbergh completed at the end June, was 38,698 boe/d. At Pembina, production averaged 5,124 boe/d during the second half of 2007, exceeding the 3,500 boe/d production level at the announcement of this acquisition in May of this year. Battery and compression modifications conducted since the purchase have increased operational reliability, which, together with improved industry cooperation, have contributed to production from this area exceeding expectations. Baytex is maintaining our 2008 average production guidance of between 37,000 and 38,000 boe/d as production is expected to be modestly curtailed by severe cold weather in the first quarter and spring break-up conditions in the second quarter. The exploration and development capital budget to deliver this production level is set at $150 million.

Financial Review

Cash flow from operations for the fourth quarter was a record $98.7 million, an increase of 32% compared to $75.0 million for the third quarter of 2007. Baytex received an average oil price of $56.37/bbl in the fourth quarter, an increase of 11% compared to $50.85/bbl in the third quarter as benchmark WTI price increased 20% to an average of US$90.68/bbl. Natural gas prices also improved in the fourth quarter, with Baytex receiving an average wellhead price of $6.31/Mcf, 9% higher than that in the third quarter. In addition to the increase in production and commodity prices, cash flow in the fourth quarter was aided by the following non-recurring items. Firstly, with the expiry of the Frontier heavy oil supply agreement on December 31, 2007, inventory in transit via the Express Pipeline was settled at year-end, resulting in an additional $6.0 million of sales proceeds being reported in the fourth quarter. A similar amount of sales proceeds from inventory adjustment will also be recorded in the first quarter of 2008. Secondly, we terminated the interest rate swap arrangement associated with our senior subordinated notes during the quarter, resulting in a cash gain of $2.0 million. We have reverted to paying the fixed rate coupon of 9.625% on these notes.

Lloyd Blend heavy oil pricing differentials averaged 36% of WTI price for the fourth quarter compared to 29% in the third quarter, in part due to lower seasonal demand. This higher differential was also caused by several operational issues in December, including the shut-down of the main pipeline to the Chicago refining region for a short period following an accident, and two refinery accidents affecting Canadian through-put. These issues have since been rectified, and Lloyd Blend differential has narrowed significantly and is expected to average below 25% in the first quarter of 2008, reflecting fundamental improvements brought on by infrastructure development and supply issues affecting the North American market.

The cash flow capability of Baytex's asset base under prevailing commodity prices is demonstrated by our results in the second half of 2007. Our average production of 38,698 boe/d in the second half was 77% weighted towards crude oil. Cash flow in this six-month period was $174 million ($2.09 per basic unit), generated under average benchmarks of WTI price at US$83.03, CAD/USD exchange rate at 1.0132, Lloyd Blend differential at 33% and AECO monthly index gas price at C$5.65/Mcf. Capital spending during this period was $84 million, or 48% of cash flow. Combined with payout ratios in the second half of 44% net of DRIP and 52% before DRIP, our financial position continued to improve alongside operational gains.

Total net monetary debt, excluding notional mark-to-market liabilities and future income tax assets at the end of the year, was $444 million and represented a reduction of $23 million from the end of the third quarter. This net debt represents 1.3 times annualized second half 2007 cash flow. Baytex's excellent financial strength, together with our industry-leading capital efficiency and prudent operational and financial practices, will position us well to continue to deliver superior market performance under the current operating environment.

Capital Program Efficiency

Since the conversion to an income trust in late 2003, Baytex has consistently demonstrated superior capital and operational efficiencies as we prudently execute our strategy for long-term sustainability. Based on the reports prepared in accordance with National Instrument ("NI") 51-101 by our independent reserves evaluator, Sproule Associates Limited ("Sproule"), the efficiency of Baytex's capital programs is summarized as follows:

	2007	Three Year Average 2005 - 2007
Excluding Changes in Future Development Costs [(1)]		
FD&A Costs – Proved ($/boe)		
Exploration and development	$ 10.03	$ 9.53
Acquisitions (net of dispositions)	20.63	10.00
Total	$ 14.75	$ 9.71
FD&A costs – Proved plus Probable ($/boe)		
Exploration and development	$ 9.17	$ 8.19
Acquisitions (net of dispositions)	12.30	7.32
Total	$ 10.90	$ 7.83
Operating Netback ($/boe)	$ 26.42	$ 26.34
Recycle Ratio – Proved plus Probable	2.4	3.4
Reserves Replacement Ratio - Proved plus Probable	274%	224%
Including Changes in Future Development Costs [(1)]		
FD&A costs – Proved ($/boe)		
Exploration and development	$ 8.82	$ 14.12
Acquisitions (net of dispositions)	22.93	12.11
Total	$ 15.10	$ 13.35
FD&A costs – Proved plus Probable ($/boe)		
Exploration and development	$ 9.27	$ 12.15
Acquisitions (net of dispositions)	14.05	8.87
Total	$ 11.91	$ 10.76

(1) 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 total finding and development costs related to reserves additions for that year.

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 as evaluated by Sproule. It does not take into account the possibility of Baytex being able to recognize additional reserves through future capital investment in our existing properties beyond those included in the 2007 year-end report.

Forecast Prices Before Tax

	($ thousands)
Proved plus probable reserves [(1)]	2,494,267
Undeveloped land [(2)]	117,907
Net debt [(3)]	(427,915)
Asset retirement obligations	(45,113)
Net asset value	2,139,146
Diluted trust units [(4)]	88,295,627
Net asset value per trust unit	$24. 23

Forecast Prices After Tax

	($ thousands)
Proved plus probable reserves [(1)]	2,214,845
Undeveloped land [(2)]	117,907
Net debt [(3)]	(427,915)
Asset retirement obligations	(45,113)
Net asset value	1,859,724
Diluted trust units [(4)]	88,295,627
Net asset value per trust unit	$21.06

Notes:
(1) Net present value of future net revenue discounted at 10% as evaluated by Sproule as at December 31, 2007. 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, 2007 on 638,975 net acres of undeveloped land.
(3) Long-term debt net of working capital as at December 31, 2007, excluding convertible debentures, future income tax assets, and notional liabilities associated with the mark-to-market value of derivative contracts.
(4) Includes 84,539,945 trust units, 1,565,615 exchangeable shares converted at an exchange ratio of 1.67915 and 1,126,780 trust units issuable on the conversion of the outstanding convertible debentures as at December 31, 2007.

Oil and Gas Reserves

Baytex announced certain of its year-end 2007 reserves information on February 20, 2008. Following is additional summary information with regard to oil and gas reserves as at December 31, 2007. Other detailed information as required under NI 51-101 will be included in Baytex's Annual Information Form.

Reconciliation of Gross Company Interest Reserves (1)
By Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			**Heavy Oil**		
	Proved (2)	**Probable (2)**	**Proved + Probable (2)**	**Proved (2)**	**Probable (2)**	**Proved + Probable (2)**
	(Mbbl)	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**
December 31, 2006	5,186	2,044	7,230	75,808	32,929	108,737
Extensions	72	21	93	8,252	3,187	11,439
Discoveries	-	-	-	-	-	-
Improved Recoveries	329	322	651	3,362	1,127	4,489
Technical Revisions	(344)	(2,463)	(2,807)	1,989	(1,014)	975
Acquisitions	6,081	5,292	11,373	2,997	770	3,767
Dispositions	-	-	-	-	-	-
Economic Factors	114	79	193	725	393	1,118
Production	(1,401)	-	(1,401)	(8,064)	-	(8,064)
December 31, 2007	10,037	5,295	15,332	85,069	37,392	122,461

	Natural Gas Liquids			**Natural Gas including solution gas**		
	Proved (2)	**Probable (2)**	**Proved + Probable (2)**	**Proved (2)**	**Probable(2)**	**Proved + Probable (2)**
	(Mbbl)	**(Mbbl)**	**(Mbbl)**	**(MMcf)**	**(MMcf)**	**(MMcf)**
December 31, 2006	3,462	1,014	4,476	108,421	39,637	148,058
Extensions	80	41	121	3,680	977	4,657
Discoveries	9	2	11	2,275	586	2,861
Improved Recoveries	-	-	-	2,767	718	3,485
Technical Revisions	(198)	170	(28)	(7,147)	(5,831)	(12,978)
Acquisitions	838	638	1,476	11,871	8,140	20,011
Dispositions	-	-	-	-	-	-
Economic Factors	12	5	17	1,039	661	1,700
Production	(600)	-	(600)	(18,937)	-	(18,937)
December 31, 2007	3,603	1,870	5,473	103,969	44,888	148,857

	Oil Equivalent (3)		
	Proved (2)	**Probable (2)**	**Proved + Probable (2)**
	(Mboe)	**(Mboe)**	**(Mboe)**
December 31, 2006	102,528	42,592	145,120
Extensions	9,017	3,412	12,429
Discoveries	388	100	488
Improved Recoveries	4,152	1,569	5,721
Technical Revisions	254	(4,277)	(4,023)
Acquisitions	11,895	8,056	19,951
Dispositions	-	-	-
Economic Factors	1,025	586	1,611
Production	(13,221)	-	(13,221)
December 31, 2007	116,038	52,038	168,076

Notes:
(1) Gross Company interest reserves include solution gas but do not include royalty interest.
(2) Reserves information as at December 31, 2006 and 2007 is prepared in accordance with NI 51-101.
(3) 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.

Management's Discussion and Analysis

Management's discussion and analysis ("MD&A"), dated March 11, 2008, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2007 and the audited consolidated financial statements and MD&A for the year ended December 31, 2006. 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, which represents an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe's may be misleading, particularly if used in isolation.

Non-GAAP Financial Measures
This MD&A refers to certain financial measures, such as payout ratio and cash flow from operations, that are not in accordance with Generally Accepted Accounting Principles ("GAAP") in Canada. These measures do not have any standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. We discuss these measures because we believe that they facilitate the understanding of the results of our operations and financial position.

Production. Light oil and natural gas liquids ("NGL") production for the fourth quarter of 2007 increased by 123% to 8,123 bbl/d from 3,643 bbl/d a year earlier primarily as a result of the acquisition of the Pembina assets near the end of the second quarter of 2007. Heavy oil production was little changed from year-ago levels, averaging 22,196 bbl/d for the fourth quarter of 2007 compared to 22,416 bbl/d a year ago. Natural gas production increased by 5% to 53.9 MMcf/d for the fourth quarter of 2007 compared to 51.4 MMcf/d for the same period last year. The increase was primarily the result of the Pembina acquisition offsetting natural declines during a quarter in which Baytex engaged in a very low level of gas development activity due to economic factors.

For the year ended December 31, 2007, light oil and NGL production increased by 47% to 5,483 bbl/d from 3,735 bbl/d for last year. Heavy oil production for 2007 increased by 4% to 22,092 bbl/d compared to 21,325 bbl/d for 2006. Natural gas production decreased by 6% to an average 51.9 MMcf/d for 2007 compared to 55.4 MMcf/d for 2006.

Revenue. Petroleum and natural gas sales increased 47% to $197.4 million for the fourth quarter of 2007 from $134.5 million for the same period in 2006**.**

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2007 were 1,717 bbl/d higher (three months ended December 31, 2006 – 28 bbl/d higher) than the production for the period due to sales of pipeline inventory pursuant to the expiry of the Frontier supply agreement. The corresponding number for the year ended December 31, 2007 was an increase of 340 bbl/d (year ended December 31, 2006 – a decrease of 4 bbl/d).

	Three Months ended December 31			
	2007		2006	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**55,872**	**74.77**	16,294	48.62
Heavy oil	**110,281**	**50.13**	84,961	41.15
Derivative contracts gain (loss)	**(4,367)**	**(1.99)**	503	0.24
Total oil revenue	**161,786**	**54.89**	101,758	42.40
Natural gas revenue (Mcf)	**31,285**	**6.31**	33,286	7.03
Total revenue (boe)	**193,071**	**51.16**	135,044	42.35

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

Revenue from light oil and NGL for the fourth quarter of 2007 increased 243% from the same period a year ago due to a 123% increases in sales volume and a 54% increase in wellhead prices. Revenue from heavy oil increased 30% as the result of a 22% increase in wellhead prices in addition to a 7% increase in sales volume. Revenue from natural gas decreased 6% as the result of a 5% increase in volume offset by a 10% decrease in wellhead prices.

	Year ended December 31			
	2007		2006	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**131,143**	**65.53**	73,387	53.84
Heavy oil	**362,549**	**44.28**	339,066	43.57
Derivative contracts gain (loss)	**(3,164)**	**(0.39)**	2,529	0.32
Total oil revenue	**490,528**	**48.14**	414,982	45.38
Natural gas revenue (Mcf)	**125,235**	**6.61**	144,236	7.13
Total revenue (boe)	**615,763**	**46.14**	559,218	44.68

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

For the year ended December 31, 2007, light oil and NGL revenue increased 79% from last year due to a 22% increase in wellhead prices and a 47% increase in volume. Revenue from heavy oil increased by 7% from last year, as a result of a 2% increase in wellhead prices and a 5% increase in sales volume. Revenue from natural gas decreased 13% compared to 2006 due to a 6% decrease in volume combined with a 7% decrease in wellhead prices.

Royalties. Total royalties increased to $32.5 million for the fourth quarter of 2007 from $18.5 million in 2006. Total royalties for the fourth quarter of 2007 were 16.5% of sales compared to 13.8% of sales for the same period in 2006. For the fourth quarter of 2007, royalties were 19.9% of sales for light oil, NGL and natural gas, and 13.7% for heavy oil. These rates compared to 16.6% and 12.1%, respectively, for the same period last year. Royalties are generally based on market index prices realized by the industry in the period, with rates increasing as price and volume escalate.

For the year ended December 31, 2007, royalties increased to $102.8 million from $85.0 million for last year. Total royalties for the year ended December 31, 2007 were 16.6% of sales, compared to 15.3% of sales a year ago. For 2007, royalties were 18.8% of sales for light oil, NGL and natural gas and 15.1% for heavy oil. These rates compared to 16.3% and 14.6%, respectively, for 2006.

Operating Expenses. Operating expenses for the fourth quarter of 2007 increased to $38.7 million from $29.8 million in the corresponding quarter last year. Operating expenses were $10.25 per boe for the fourth quarter of 2007 compared to $9.36 per boe for the fourth quarter of 2006. For the fourth quarter of 2007, operating expenses were $9.67 per boe of light oil, NGL and natural gas, and $10.66 per barrel of heavy oil. The operating expenses for the same period a year ago were $9.15 and $9.47, respectively. The increase in operating costs for conventional oil and gas was in part due to the addition of higher cost sour operations at Pembina. With respect to our operations, in general, the inflationary environment affecting operating costs has not entirely subsided as certain cost categories such as property taxes, labour costs and fuel costs continued to increase. This is particularly prevalent in heavy oil operating areas as industry activity levels remain strong due to robust economics associated with the current heavy oil pricing environment.

Operating expenses for 2007 increased to $134.7 million from $112.4 million in 2006. Operating expenses were $10.09 per boe for 2007 compared to $8.98 per boe for the prior year. In 2007, operating expenses were $9.61 per boe of light oil, NGL and natural gas and $10.40 per barrel of heavy oil compared to $8.58 and $9.23, respectively, for the year earlier.

Transportation Expenses. Transportation expenses for the fourth quarter of 2007 were $7.5 million compared to $6.4 million for the fourth quarter of 2006. These expenses were $1.98 per boe for the fourth quarter of 2007 compared to $2.00 for the same period in 2006. Transportation expenses were $0.67 per boe of light oil, NGL and natural gas and $2.92 per barrel of heavy oil. The corresponding amounts for fourth quarter of 2006 were $0.82 and $2.64, respectively.

Transportation expenses for 2007 were $28.8 million compared to $24.3 million for 2006. These expenses were $2.16 per boe in 2007 compared to $1.95 in 2006. Transportation expenses were $0.80 per boe of light oil, NGL and natural gas and $3.01 per barrel of heavy oil in 2007, compared to $0.87 and $2.60, respectively, in 2006. The increase in transportation expenses for heavy oil primarily reflects higher fuel costs and longer haul distances for production at Seal in order to access higher value markets.

General and Administrative Expenses. General and administrative expenses for the fourth quarter of 2007 increased to $6.8 million from $5.9 million a year earlier. On a per sales unit basis, these expenses were $1.81 per boe for the fourth quarter of 2007 compared to $1.84 per boe for the same period in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

General and administrative expenses for 2007 were $23.6 million, compared to $20.8 million for the prior year. On a per sales unit basis, these expenses were $1.77 per boe in 2007 and $1.67 per boe in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either 2007 or 2006.

Unit-based Compensation Expense. Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2007 compared to $2.2 million for the fourth quarter of 2006. For the year-ended December 31, 2007, compensation expense was $8.0 million compared to $7.5 million for 2006.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expenses. Interest expense for the fourth quarter of 2007 remained consistent at $8.7 million compared to the same quarter last year. Interest expense was affected by the recognition of a $2.0 million gain on the termination of the interest rate swap associated with the senior subordinated notes, a more favourable exchange rate on the U.S. dollar denominated interest expenses, offset by the accretion of the deferred adjustment on adoption of Section 3865 and by higher interest on increased bank borrowings.

In 2007, interest expense was $35.2 million compared to $35.0 million for last year. The items affecting interest expense are the same factors influencing the fourth quarter variance.

Foreign Exchange. Foreign exchange gain in the fourth quarter of 2007 was $1.3 million compared to a loss of $9.0 million in the fourth quarter of 2006. The 2007 amount is comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.2 million. The loss in the 2006 period was entirely unrealized. The current quarter's unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 1.0037 at September 30, 2007. The prior period loss is based on translation at 0.8581 at December 31, 2006 compared to 0.8966 at September 30, 2006.

Foreign exchange gain for 2007 was $32.5 million compared to $0.1 million in the prior year. The 2007 gain is comprised of an unrealized foreign exchange gain of $32.6 million and a realized foreign exchange loss of $0.1 million. The 2006 gain was substantially unrealized. The 2007 unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 0.8581 at December 31, 2006. The 2006 unrealized gain is based on translation at 0.8581 at December 31, 2006 compared to 0.8577 at December 31, 2005.

Depletion, Depreciation and Accretion. The provision for depletion, depreciation and accretion for the fourth quarter of 2007 increased to $54.1 million from $39.5 million for the same quarter in 2006. On a sales-unit basis, the provision for the current quarter was $14.33 per boe compared to $12.38 per boe for the same quarter in 2006. The higher rate is due to increased future development costs reflected in the reserves evaluation, the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Depletion, depreciation and accretion increased to $189.5 million for the year ended December 31, 2007 compared to $152.6 million for 2006. On a sales-unit basis, the provision for the current year was $14.20 per boe compared to $12.19 per boe for 2006. The increase is attributable to the same factors influencing the fourth quarter calculations.

Taxes. On June 22, 2007, the federal government's bill (the "government's bill") regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received Royal Assent. As a result, a future income tax recovery of $0.5 million was recognized in the second quarter relating to unutilized tax pools in the Trust which will be deductible to the Trust after 2010. The majority of the Trust's temporary differences resides in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

The government's bill provides that the new tax regime for income trusts will not apply until January 1, 2011 so long as the Trust experiences only "normal growth" and no "undue expansion". As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40 percent of that trust's October 31, 2006 market capitalization for the period November 1, 2006 to December 31, 2007, and an additional 20 percent of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006 / 2007 and $365 million for each of the subsequent three years. Issuance of equity or convertible debt beyond these limits will result in the new regime applying to the Trust before 2011.

The provision for future income taxes for the current quarter was a recovery of $27.6 million compared to a recovery of $10.2 million in the same period in 2006. For the year ended December 31, 2007, the provision for future income taxes was a recovery of $49.3 million compared to a recovery of $41.2 million for 2006. As a result of the Pembina/Lindbergh acquisition, Baytex recognized a future income tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Current tax of $2.1 million for the fourth quarter of 2007 is comprised primarily of Saskatchewan Capital Tax and Resource Surcharge. Current tax for the same period a year ago was $2.5 million which included $1.8 million of Saskatchewan Capital Tax and Resource Surcharge and a $0.7 million adjustment of Large Corporation Tax, which tax was eliminated during 2006.

Current tax expenses were $6.7 million for the year ended December 31, 2007 compared to $8.4 million for 2006. The 2007 current tax expense is comprised of $7.2 million of Saskatchewan Capital Tax and Resource Surcharge and a recovery of $0.5 million relating to prior period recoveries. The 2006 current tax expense included $8.2 million of Saskatchewan Capital Tax and Resource Surcharge, a recovery of $0.4 million of Large Corporation Taxes and $0.6 million of prior period adjustments.

Net Income. Net income for the fourth quarter of 2007 was $41.4 million compared to $20.0 million for the fourth quarter in 2006. The variance was the result of higher production, higher sales prices, foreign exchange gains and future income tax recovery, offset by higher operating costs.

Net income for 2007 was $132.9 million compared to $147.1 million for 2006. The variance was due to higher operating and transportations costs, higher depletion rates, and higher general and administrative costs. These negative factors were partially offset by higher sales volumes and prices and a higher foreign exchange gain.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's payout ratio is calculated as cash distributions declared divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

	Three Months Ended			Year Ended	
	December 31, 2007	September 30, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Cash flow from operating activities	**$ 100,131**	$ 73,722	$ 60,999	**$ 286,450**	$ 261,982
Change in non-cash working capital	**(3,145)**	308	1,878	**(5,140)**	9,058
Asset retirement expenditures	**1,131**	351	233	**2,442**	1,747
Decrease (increase) in deferred charges and other assets	**550**	576	409	**2,278**	1,875
Cash flow from operations	**$ 98,667**	$ 74,957	$ 63,519	**$ 286,030**	$ 274,662
Cash Distributions declared	**$ 37,314**	$ 38,746	$ 34,516	**$ 145,927**	$ 143,072
Payout ratio (1)	**38%**	52%	54%	**51%**	52%

(1) Payout ratio is calculated as cash distributions declared divided by cash flow from operations

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserves reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions of $37.3 million for the fourth quarter of 2007 were funded through cash flow from operations of $98.7 million. For the year ended December 31, 2007, cash distributions of $145.9 million were funded through cash flow from operations of $286.0 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	Three Months Ended December 31,		Year Ended December 31,	
	2007	2006	**2007**	2006
Cash flow from operating activities	**$ 100,131**	$ 60,999	**$ 286,450**	$ 261,982
Actual cash distributions payable	**37,314**	34,516	**145,927**	143,072
Excess of cash flow from operating activities over cash distributions paid	**$ 62,817**	$ 26,483	**$ 140,523**	$ 118,910
Net Income	**$ 41,353**	$ 19,988	**$ 132,860**	$ 147,069
Actual cash distributions payable	**37,314**	34,516	**145,927**	143,072
Excess (shortfall) of net income over cash distributions paid	**$ 4,039**	$ (14,528)	**$ (13,067)**	$ 3,997

It is Baytex's long term operating objective to substantially fund cash distributions and capital expenditures required to maintain production and reserves through cash flow from operating activities. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of temporary decline in commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall will be funded through a combination of equity and debt financing. As at December 31, 2007, Baytex had approximately $120 million in available credit facilities to fund such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the three months ended December 31, 2007, the Trust's net income exceeded cash distributions by $4.0 million. For the year ended December 31, 2007, the Trust's cash distribution exceeded net income by $13.1 million with net income reduced by $153.6 million of non-cash items. Non-cash charges such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

Liquidity and Capital Resources. At December 31, 2007, total net monetary debt was $444 million compared to $367 million at the end of 2006. The increase is mainly attributable to the bank loan incurred to partially finance the acquisition of the Pembina and Lindbergh properties at the end of the second quarter. Bank borrowings and working capital deficiency at the end of fourth quarter 2007 was $250.1 million compared to total credit facilities of $370 million. The syndicated credit facilities were increased from $300 million to $370 million during June 2007.

Corporate Acquisition. On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which had interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since June 26, 2007. The acquisition was financed partly by the issuance of equity and partly by bank loan. Subsequent to the acquisition, the private company was amalgamated with Baytex.

Capital Expenditures

Capital expenditures for the three months and years ended December 31, 2007 and 2006 are summarized as follows:

	Three Months Ended December 31,		**Year Ended December 31**	
($thousands)	**2007**	2006	**2007**	2006
Land	**1,197**	3,277	**7,253**	11,118
Seismic	**471**	239	**1,994**	2,202
Drilling and completion	**23,041**	18,019	**108,106**	97,273
Equipment	**8,148**	2,439	**26,624**	19,240
Other	**1,492**	369	**4,742**	2,548
Total exploration and development	**34,349**	24,343	**148,719**	132,381
Corporate acquisition (net of working capital)	**3,389**	-	**243,273**	-
Property acquisitions	**2,038**	37	**2,877**	1,530
Property dispositions	**(363)**	(30)	**(723)**	(828)
Total capital expenditures	**39,413**	24,350	**394,146**	133,083

Changes in Accounting Policies. Effective January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income" and section 3861 "Financial Instruments – Disclosure and Presentation". These standards have been adopted prospectively. See Note 2 to the Consolidated Financial Statements for further detail and the impact on the Trust's financial statements from application of these new standards.

Effective January 1, 2007 the Trust also adopted the recommendation of CICA revised section 1506 "Accounting Changes" and section 3251 "Equity". The revised section 1506 provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors. The revised section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Baytex.

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

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

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

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

The New Royalty Framework

On September 18, 2007, the Royalty Review Panel appointed by the Alberta government released a report entitled "Our Fair Share", providing recommendations on changes to the province's royalty regime. On October 25, 2007, the Alberta government announced the "New Royalty Framework", accepting many of the recommendations by the Royalty Review Panel. Major changes introduced to Alberta's royalty regime effective January 2009 are as follows:

Conventional oil – overall royalty rates will increase from the current maximum of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to $120 per barrel for West Texas Intermediate (WTI) crude.

Natural gas – the Government will eliminate "old" and "new" tiers. Royalty rates, currently 5% to 35% will increase to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at Cdn$16.59/GJ.

Oil Sands – currently, the pre-payout royalty rate is 1%. Under the new system, this rate will increase for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the current regime, once an oil sands project reaches payout, the 1% royalty converts to a 25% net profits interest. Under the new regime, the net profits interest will apply at the rate of 25% when oil is less than $55 per bbl of WTI, and increase for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed.

As previously reported, we had requested that our reserves evaluator, Sproule, estimate the impact to our reserves evaluation based upon the currently released information on the new royalty regime. As of December 31, 2007, the province had not introduced the enabling legislation nor had they provided enough clarity on a number of issues for Sproule to provide a precise calculation of reserves and net present value under the new regime. It is possible that the announced changes may be amended before coming into force. Under the forecast price assumptions, Sproule has estimated that the change to the net present value, discounted at 10%, of future net revenue from our proved plus probable reserves would be a reduction of 2.1%.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1 per cent to 15 per cent. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25 per cent combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the specified investment flow-through ("SIFT") tax rate to 28 per cent as compared to the rate of 31.5 per cent previously announced subject to comments below concerning the provincial SIFT Tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law trust taxation that will result in a tax of 29.5 per cent (previously 31.5 per cent as discussed above) on all trust distributions commencing January 1, 2011 (28 percent commencing January 1, 2012.). Cash flow earned by the trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

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

Currently, the SIFT Rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined SIFT tax rate of 29.5% in 2011. On February 26, 2008, the Minister of Finance announced (the "Provincial SIFT Tax Proposal") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

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

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

Disclosure Controls and Procedures

As of December 31, 2007, an internal evaluation was conducted of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 (the "Exchange Act') and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act or under Canadian securities legislation is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

Internal Controls over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management has assessed the effectiveness of the Trust's internal control over financial reporting as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2007. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, as reflected in their report for 2007. No changes were made to our internal controls over financial reporting during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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 Wednesday, March 12, 2008 to discuss our 2007 results. The conference call will be hosted by Raymond Chan, Chief Executive Officer, Anthony Marino, President and Chief Operating Officer, and Derek Aylesworth, Chief Financial Officer. Interested parties are invited to participate by calling toll-free across North America at 1-800-771-7943. An archived recording of the call will be available from March 12, 2008 until March 26, 2008 by dialing 1-800-558-5253 or 416-626-4100 within the Toronto area, and entering the access code 21374995. 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, 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 reserves 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.

Baytex Energy Trust is a conventional oil and gas income trust focused on maintaining its production and asset base through internal property development and delivering consistent returns to its unitholders. Trust units of Baytex are traded on the Toronto Stock Exchange under the symbol BTE.UN and on the New York Stock Exchange under the symbol BTE.

Financial statements for the periods ended December 31, 2007 and 2006 are attached.

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Baytex Energy Trust
Consolidated Balance Sheets
(thousands)

	December 31, 2007	December 31, 2006
Assets		
Current assets		
Accounts receivable	**$ 105,176**	$ 64,716
Crude oil inventory	**5,997**	9,609
Financial derivative contracts (note 14)	**-**	3,448
Future income taxes	**11,525**	-
	122,698	77,773
Deferred charges and other assets	**-**	4,475
Petroleum and natural gas properties	**1,246,697**	959,626
Goodwill	**37,755**	37,755
	$ 1,407,150	$ 1,079,629
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 104,318**	$ 71,521
Distributions payable to unitholders	**15,217**	13,522
Bank loan	**241,748**	127,495
Financial derivative contracts (note 14)	**34,239**	1,055
	395,522	213,593
Long-term debt (note 4)	**173,854**	209,691
Convertible debentures (note 5)	**16,150**	18,906
Asset retirement obligations (note 6)	**45,113**	39,855
Deferred obligations (note 15)	**113**	2,391
Future income taxes	**153,943**	118,858
	784,695	603,294
Non-controlling interest (note 8)	**21,235**	17,187
Unitholders' Equity		
Unitholders' capital (note 7)	**821,624**	637,156
Conversion feature of debentures (note 5)	**796**	940
Contributed surplus (note 9)	**18,527**	13,357
Deficit	**(239,727)**	(192,305)
	601,220	459,148
	$ 1,407,150	$ 1,079,629

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Income and Comprehensive Income
(thousands, except per unit data)

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Revenue				
Petroleum and natural gas sales	**$ 197,438**	$ 134,541	**$ 618,927**	$ 556,689
Royalties	**(32,524)**	(18,539)	**(102,805)**	(85,043)
Gain (loss) on financial derivatives (note 14)	**(31,631)**	95	**(34,484)**	(261)
	133,283	116,097	**481,638**	471,385
Expenses				
Operating	**38,686**	29,848	**134,696**	112,406
Transportation	**7,470**	6,376	**28,796**	24,346
General and administrative	**6,815**	5,883	**23,565**	20,843
Unit based compensation (note 9)	**1,810**	2,168	**7,986**	7,460
Interest (note 12)	**8,650**	8,738	**35,242**	34,973
Foreign exchange loss (gain) (note 13)	**(1,317)**	9,009	**(32,494)**	(121)
Depletion, depreciation and accretion	**54,086**	39,488	**189,512**	152,579
	116,200	101,510	**387,303**	352,486
Income before taxes and non-controlling interest	**17,083**	14,587	**94,335**	118,899
Taxes (recovery) (note 11)				
Current	**2,109**	2,466	**6,713**	8,414
Future	**(27,659)**	(10,167)	**(49,369)**	(41,169)
	(25,550)	(7,701)	**(42,656)**	(32,755)
Income before non-controlling interest	**42,633**	22,288	**136,991**	151,654
Non-controlling interest (note 8)	**(1,280)**	(2,300)	**(4,131)**	(4,585)
Net income/Comprehensive income	**$ 41,353**	$ 19,988	**$ 132,860**	$ 147,069

Consolidated Statements of Deficit

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Deficit, beginning of period, as previously reported	**$ (239,473)**	$ (171,813)	**$ (192,305)**	$ (181,118)
Cumulative effect of change in accounting policy (note 2)	**3,951**	-	**(6,215)**	-
Deficit, beginning of period, restated	**(235,522)**	(171,813)	**(198,520)**	(181,118)
Net Income	**41,353**	19,988	**132,860**	147,069
Distributions to unitholders	**(45,558)**	(40,480)	**(174,067)**	(158,256)
Deficit, end of period	**$ (239,727)**	$ (192,305)	**$ (239,727)**	$ (192,305)
Net income per trust unit (note 10)				
Basic	**$ 0.49**	$ 0.27	**$ 1.66**	$ 2.02
Diluted	**$ 0.48**	$ 0.26	**$ 1.60**	$ 1.91
Weighted average trust units (note 10)				
Basic	**84,267**	74,848	**80,029**	72,947
Diluted	**89,898**	78,408	**85,975**	80,438

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
(thousands)

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income	**$ 41,353**	$ 19,988	**$ 132,860**	$ 147,069
Items not affecting cash:				
Unit based compensation (note 9)	**1,810**	2,168	**7,986**	7,460
Amortization of deferred charges (note 12)	**-**	304	**-**	1,267
Unrealized foreign exchange loss (gain) (note 13)	**(1,526)**	8,997	**(32,574)**	(108)
Depletion, depreciation and accretion	**54,086**	39,488	**189,512**	152,579
Accretion on debentures and notes (note 2 & note 5)	**2,059**	33	**2,164**	189
Unrealized loss (gain) on financial derivatives (note 14)	**27,264**	408	**31,320**	2,790
Future income tax recovery	**(27,659)**	(10,167)	**(49,369)**	(41,169)
Non-controlling interest (note 8)	**1,280**	2,300	**4,131**	4,585
	98,667	63,519	**286,030**	274,662
Change in non-cash working capital	**3,145**	(1,878)	**5,140**	(9,058)
Asset retirement expenditures	**(1,131)**	(233)	**(2,442)**	(1,747)
Decrease in deferred charges and other assets	**(550)**	(409)	**(2,278)**	(1,875)
	100,131	60,999	**286,450**	261,982
FINANCING ACTIVITIES				
Increase (decrease) in bank loan	**(17,580)**	(3,189)	**114,253**	3,907
Payments of distributions	**(37,415)**	(35,079)	**(144,609)**	(141,453)
Issue of trust units, net of issuance costs (note 7)	**1,363**	1,427	**147,221**	8,509
	(53,632)	(36,841)	**116,865**	(129,037)
INVESTING ACTIVITIES				
Petroleum and natural gas property expenditures	**(34,349)**	(24,343)	**(148,719)**	(132,381)
Corporate acquisition (note 3)	**(3,389)**	-	**(243,273)**	-
Acquisition of working capital (note 3)	**-**	-	**(13,229)**	-
Acquisition of petroleum and natural gas properties	**(2,038)**	(37)	**(2,877)**	(1,530)
Disposal of petroleum and natural gas properties	**363**	30	**723**	828
Change in non-cash working capital	**(7,086)**	192	**4,060**	138
	(46,499)	(24,158)	**(403,315)**	(132,945)
Change in cash and cash equivalents	-	-	**-**	-
Cash and cash equivalents, beginning of period	-	-	**-**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Three Months and Year ended December 31, 2007 and 2006
(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 and Baytex Energy Ltd. (the "Company"). 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.

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.

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, 2006, except as noted below. 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, 2006.

2. Changes in Accounting Policies

Financial Instruments and Hedging Activities

Effective January 1, 2007, the Trust adopted the provisions of the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income", section 3861 "Financial Instruments – Disclosure and Presentation" and section 3251 "Equity". The Trust has adopted these standards retrospectively and the comparative interim consolidated financial statements have not been restated. Transitional amounts have been recorded in deficit.

Financial Instruments

A. Classification

All financial instruments must initially be recognized at fair value on the balance sheet. All financial instruments must be classified into one of the following categories: "held for trading financial assets and liabilities", "loans and receivables", "held to maturity investments", "available for sale financial assets" and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification.

The Trust has made the following classifications:

- Cash and cash equivalents are classified as held for trading and are measured at fair value, which approximates carrying value due to the short-term nature of these instruments. A gain or loss arising from a change in the fair value is recognized in net income in the current period.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value and subsequently measured at amortized cost using the effective interest method. A gain or loss arising from a change in the fair value or the derecognition or impairment of assets is recognized in net income in the period.
- Accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, long term debt and deferred obligations have been classified as other financial liabilities and are initially recognized at fair value. Upon issuance, the Trust's convertible debentures are classified into equity and financial liability components on the balance sheet at their fair value. The financial liability is classified as other financial liabilities. The above instruments are subsequently measured at amortized cost using the effective interest method. A gain or loss is recognized in net income in the period when the financial liability is derecognized or impaired and through the amortization process.
- All derivative instruments have been classified as held for trading and are measured at fair value. A gain or loss arising from a change in the fair value is recognized in net income in the current period.

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

B. Transaction Costs

The Trust has elected to expense all financial instrument transaction costs immediately.

C. Effective Interest Method

The Trust uses the effective interest method of amortization for the discount on its convertible debentures and the deferred adjustment on the long-term notes.

D. Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract if all of the following are met: (1) their economic characteristics and risks are not closely related to the host contract; (2) a separate instrument with similar terms as the embedded derivative would meet the definition of a derivative; and (3) the hybrid instrument is not measured at fair value. The Company has selected January 1, 2007 as its transition date for accounting for any potential embedded derivatives.

Hedge Accounting
On January 1, 2007, the Trust chose to discontinue hedge accounting on its interest rate swap. Effective January 1, 2007 a financial liability was recorded on the balance sheet. Any changes in the fair value of the swap were recorded in net income.

Comprehensive Income
Comprehensive income consists of net earnings and other comprehensive income ("OCI"). OCI includes gains and losses on derivatives designated as cash flow hedges, gains and losses arising from changes in fair value of available for sale assets and unrealized gains and losses on translating financial statements of self sustaining foreign operations, all net of tax. Accumulated other comprehensive income is a new equity category comprised of cumulative OCI. The Trust has not engaged in any transactions giving rise to OCI as of December 31, 2007.

Transitional Adjustment
The impact of adopting these standards as at January 1, 2007 is as follows:

	As at December 31, 2006	Adjustment Upon Adoption of New Standards	As at January 1, 2007
Assets			
Deferred charges	$ 4,475	**$ (4,475)**	**$ -**
Liabilities			
Financial derivative contracts	1,055	$ 5,976	7,031
Long-term debt	209,691	(5,976)	203,715
Future income taxes	118,858	(1,265)	117,593
		(1,265)	
Unitholders' Equity			
Unitholders' capital	637,156	3,005	640,161
Deficit	(192,305)	(6,215)	(198,520)
		(3,210)	
		$ (4,475)	

Accounting Changes

Effective January 1, 2007, the Trust adopted the recommendation of CICA revised section 1506 "Accounting Changes". The new standard provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors.

Future Accounting Changes

On December 1, 2006, the CICA issued three new accounting standards:
Handbook Section 1535, Capital Disclosures, Section 3862, Financial instruments - Disclosures, and Section 3863, Financial instruments - Presentation. These new standards will be effective on January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, which replaces Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new Section to have a material impact on its consolidated financial statements.

3. Acquisition

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which has interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been 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:

Consideration for the acquisition	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502
Allocation of purchase price	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

Amendments may be made to the purchase equation as the cost estimates and balance are finalized.

4. Long-term Debt

	December 31, 2007	December 31, 2006
10.5% senior subordinated notes (US$247)	**$ 244**	$ 288
9.625% senior subordinated notes (US$179,699)	**177,561**	209,403
	177,805	209,691
Discontinued fair value hedge	**(3,951)**	-
	$ 173,854	$ 209,691

The Company has US$247,000 senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The US$179.7 million of 9.625% senior subordinated notes, due July 15, 2010, are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2007 at 104.813%, 2008 at 102.406%, 2009 and thereafter at 100%. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of Section 3865 (note 2). The notes will accrete up to the principal balance at maturity using the effective interest method. $2.0 million of accretion expense had been recorded for 2007. The effective interest rate is 10.666% The Company had an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2% until the maturity of these notes. On November 29, 2007 the Company unwound the interest rate swap contract. A gain on termination of $2.0 million has been recorded as a reduction to interest expense.

On January 1, 2007, the Trust chose to discontinue hedge accounting on its interest rate swap. Effective January 1, 2007 a financial liability was recorded on the balance sheet.

5. Convertible Unsecured Subordinated Debentures

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.57%. The accretion, and the interest paid are expensed as interest expense in the consolidated statement of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Principal Amount of Debentures	**Book Value of Debentures**	**Book Value of Conversion Feature**
Balance, December 31, 2005	$ 77,152	$ 73,766	$ 3,698
Conversion	(57,533)	(55,049)	(2,758)
Accretion	-	189	-
Balance, December 31, 2006	19,619	18,906	940
Conversion	(2,999)	(2,895)	(144)
Accretion	-	139	-
Balance, December 31, 2007	$ 16,620	$ 16,150	$ 796

6. Asset Retirement Obligations

	2007	2006
Balance, beginning of year	**$ 39,855**	$ 33,010
Liabilities incurred	**2,180**	1,199
Liabilities acquired	**2,239**	-
Liabilities settled	**(2,442)**	(1,747)
Disposition of liabilities	**(585)**	(122)
Accretion	**3,404**	2,678
Change in estimate(1)	**462**	4,837
Balance, end of year	**$ 45,113**	$ 39,855

(1) Change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

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. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2007 is $268 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 2.0%.

7. Unitholders' Capital

Trust Units

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

	Number of Units	**Amount**
Balance, December 31, 2005	69,283	$ 555,020
Issued on conversion of debentures	3,901	54,798
Issued on conversion of exchangeable shares	34	720
Issued on exercise of trust unit rights	1,250	8,509
Transfer from contributed surplus on exercise of trust unit rights	-	4,435
Issued pursuant to distribution reinvestment program	654	13,674
Balance, December 31, 2006	75,122	637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	-	2,816
Issued pursuant to distribution reinvestment program	1,464	27,763
Cumulative effect of change in accounting policy (Note 2)	-	3,005
Balance, December 31, 2007	84,540	$ 821,624

8. 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 a cash payment 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 calculated monthly based on the cash distribution paid divided by the weighted average trust unit price for the five day trading period ending on the record date. The exchange ratio at December 31, 2007 was 1.67915 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's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares		Amount
Balance, December 31, 2005	1,597	$	12,810
Exchanged for trust units	(24)		(208)
Non-controlling interest in net income	-		4,585
Balance, December 31, 2006	1,573		17,187
Exchanged for trust units	(7)		(83)
Non-controlling interest in net income	-		4,131
Balance, December 31, 2007	1,566	$	21,235

9. Trust Unit Rights Incentive Plan

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $1.8 million for the three months ended December 31, 2007 ($2.2 million in 2006) and $8.0 million for the year ended December 31, 2007 ($7.5 million in 2006) pursuant to rights granted under the Plan.

Effective January 1, 2006, the Trust commenced using the binomial-lattice model to calculate the estimated fair value of $3.87 per unit for unit rights issued during 2007 ($4.34 per unit in 2006). The following assumptions were used to arrive at the estimate of fair values:

	2007	2006
Expected annual right's exercise price reduction	**$2.16**	$2.16
Expected volatility	**28%**	23% - 28%
Risk-free interest rate	**3.77% - 4.50%**	3.54% - 4.45 %
Expected life of right (years)	**Various (1)**	Various (1)

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Trust Unit Rights Incentive Plan.

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

	Number of Rights	Weighted Average Exercise Price [1]
Balance, December 31, 2005	5,366	$ 10.88
Granted	2,443	$ 21.66
Exercised	(1,250)	$ 6.81
Cancelled	(246)	$ 11.54
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67

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

The following table summarizes information about the unit rights outstanding at December 31, 2007:

Range of Exercise Prices	Number Outstanding at December 31, 2007	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at December 31, 2007	Weighted Average Exercise Price
		(years)			
$ 1.09 to $ 4.50	551	0.7	$ 2.27	551	$ 2.27
$ 4.51 to $ 8.00	771	1.9	$ 6.19	745	$ 6.15
$ 8.01 to $ 11.50	1,495	2.8	$ 10.23	923	$ 10.31
$ 11.51 to $ 15.00	450	3.0	$ 12.86	169	$ 12.56
$ 15.01 to $ 18.50	477	4.1	$ 17.77	78	$ 17.73
$ 18.51 to $ 21.89	3,918	4.3	$ 19.61	551	$ 19.94
$ 1.09 to $ 21.89	7,662	3.4	$ 14.67	3,017	$ 9.89

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2005	$ 10,332
Compensation expense	7,460
Transfer from contributed surplus on exercise of trust unit rights [1]	(4,435)
Balance, December 31, 2006	13,357
Compensation expense	7,986
Transfer from contributed surplus on exercise of trust unit rights [1]	(2,816)
Balance, December 31, 2007	$ 18,527

(1) Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

10. Net Income Per Unit

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

Three Months Ended

	December 31, 2007			December 31, 2006		
	Net Income	**Trust Units**	**Net Income per Unit**	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	**$ 41,353**	**84,267**	**$ 0.49**	$ 19,988	74,848	$ 0.27
Dilutive effect of trust unit rights	**-**	**1,858**		-	2,150	
Conversion of convertible debentures	**203**	**1,144**		234	1,410	
Exchange of exchangeable shares	**1,279**	**2,629**		-	-	
Net income per diluted unit	**$ 42,835**	**89,898**	**$ 0.48**	$ 20,222	78,408	$ 0.26

Year Ended

	December 31, 2007			December 31, 2006		
	Net Income	**Trust Units**	**Net Income per Unit**	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	**$ 132,860**	**80,029**	**$ 1.66**	$ 147,069	72,947	$ 2.02
Dilutive effect of trust unit rights	**-**	**2,110**		-	2,592	
Conversion of convertible debentures	**855**	**1,206**		1,647	2,515	
Exchange of exchangeable shares	**4,131**	**2,630**		4,585	2,384	
Net income per diluted unit	**$ 137,846**	**85,975**	**$ 1.60**	$ 153,301	80,438	$ 1.91

The dilutive effect of trust unit rights for the year ended December 31, 2007 did not include 4.1 million trust unit rights (2006 – 2.1 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services not yet recognized exceeded the average market price of the trust units during the period.

11. Income Taxes (Recovery)

The provision for (recovery of) income taxes has been computed as follows:

	2007	2006
Income before income taxes and non-controlling interest	**$ 94,335**	$ 118,899
Expected income taxes at the statutory rate of 34.02% (2006 – 37.00%)	**32,094**	43,992
Increase (decrease) in taxes resulting from:		
Resource allowance	**-**	(11,236)
Alberta royalty tax credit	**-**	(110)
Net income of the Trust	**(62,615)**	(56,261)
Non-taxable portion of foreign exchange gain	**(5,424)**	(20)
Effect of change in tax rate	**(15,806)**	(26,218)
Effect of change in opening tax pool balances	**(834)**	3,451
Effect of change in valuation allowance	**2,075**	1,597
Unit based compensation	**2,717**	2,760
Other	**(1,576)**	876
Recovery of income taxes	**(49.369)**	(41,169)
Current taxes	**6,713**	8,414
Total taxes	**$ (42,656)**	$ (32,755)

On June 22, 2007, Bill C-52 Budget Implementation Act which contains legislative provisions to tax publicly traded income trusts in Canada received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted an additional future tax recovery of $0.5 million has been recorded.

The net future income tax liability is comprised of the following:

	As at December 31	
	2007	2006
Future income tax liabilities:		
Petroleum and natural gas properties	**$ 155,921**	$ 136,955
Other	**18,271**	10,019
Future income tax assets:		
Asset retirement obligations	**(11,796)**	(11,987)
Loss carry-forward [1]	**(8,058)**	(12,049)
Other	**(11,920)**	(4,080)
Net future income tax liabilities	**$ 142,418**	$ 118,858
Current portion of net future income tax assets	**$ (11,525)**	$ -
Long-term portion of net future income tax liabilities	**$ 153,943**	$ 118,858

[1] $41 million of the loss carry-forward to expire in 2014, $18 million to expire in 2015 and $3 million in 2016.

12. Interest Expense

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

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Bank loan and miscellaneous financing	**$ 3,738**	$ 2,467	**$ 13.376**	$ 9,276
Amortization of deferred charge	**-**	304	**-**	1,267
Convertible debentures	**308**	372	**1,295**	2,614
Long-term debt	**4,604**	5,595	**20.571**	21,816
Total interest	**$ 8,650**	$ 8,738	**$ 35,242**	$ 34,973

13. Supplemental Cash Flow Information

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Interest paid	**$ 2,340**	$ 2,902	**$ 32,321**	$ 32,373
Income taxes paid	**$ 2,242**	$ 1,973	**$ 9,436**	$ 7,636

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Unrealized foreign exchange gain (loss)	**$ 1,526**	$ (8,997)	**$ 32,574**	$ 108
Realized foreign exchange gain (loss)	**(209)**	(12)	**(80)**	13
Total Foreign exchange gain (loss)	**$ 1,317**	$ (9,009)	**$ 32,494**	$ 121

14. Financial Derivative Contracts

At December 31, 2007, the Trust had the following derivative contracts:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2008	2,000 bbl/d	US$60.00 – $80.25	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $77.05	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $80.10	WTI

FOREIGN CURRENCY

	Period	Amount	Rate
Swap	January 1, 2008 to June 30, 2008	US$10,000,000 per month	CAD/US$0.9935

This contract is extendable on similar terms on June 30, 2008, at the option of the counterparty, for a further six months to the end of 2008.

The financial derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Realized gain (loss) on financial derivatives	**$ (4,367)**	$ 503	**$ (3,164)**	$ 2,529
Unrealized gain (loss) on financial derivatives	**(27,264)**	(408)	**(31,320)**	(2,790)
	$ (31,631)	$ 95	**$ (34,484)**	$ (261)

15. COMMITMENTS AND CONTINGENCIES

In 2007, the Trust entered into long-term crude oil supply contracts with third parties that require the delivery of 15,340 barrels per day of crude oil in 2008 and 10,340 in 2009. The details of these contracts are:

HEAVY OIL

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2008	13,340 bbl/d	WTI x 67.1% (weighted average)
Price Swap – LLB Blend	Calendar 2008	2,000 bbl/d	WTI less US$24.55
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)

At December 31, 2007, the Trust had the following natural gas physical sales contracts:

GAS

	Period	Volume	Price/GJ
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$6.65 - $8.60
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$6.65 - $9.00
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$6.65 - $8.05
Price collar	Calendar 2008	5,000 GJ/d	$6.15 - $7.00
Price collar	Calendar 2008	5,000 GJ/d	$6.15 - $7.46

The following contracts were entered into subsequent to December 31, 2007:

GAS

	Period	Volume	Price/GJ
Price collar	April 1, 2008 to October 31, 2008	5,000 GJ/d	$6.15 - $7.50
Price collar	April 1, 2008 to October 31, 2008	2,500 GJ/d	$6.15 - $9.35

At December 31, 2007, the Trust had operating lease and transportation obligations as summarized below:

	Payments Due Within					
	Total	1 year	2 years	3 years	4 years	5 years
Operating leases	$ 5,983	$ 2,459	$ 2,435	$ 883	$ 124	$ 82
Processing and Transportation agreements	22,364	6,537	5,708	5,213	4,825	81
Total	$ 28,347	$ 8,996	$ 8,143	$ 6,096	$ 4,949	$ 163

OTHER

At December 31, 2007, there were outstanding letters of credit aggregating $4.9 million (December 31, 2006 - $7.3 million) issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value of $7.8 million of the original obligation is being drawn down over the life of the obligations, which continue until October 2008. The fair value of the remaining obligation at December 31, 2007 was $2.4 million, all of which was included in current liabilities.

In connection with a purchase of properties, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at December 31, 2007, an additional $0.7 million was paid for year two’s obligations ($0.5 million was paid for year one) under the agreement and has been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust’s financial position or reported results of operations.