HIGHLIGHTS

Baytex Energy Trust (TSX: BTE.UN; NYSE: BTE) of Calgary, Alberta is pleased to announce its operating and financial results for the three months ended March 31, 2006.

Highlights of the first quarter in 2006 include:

- Achieved record cash flow of $69.7 million, 57% higher than Q1/05 and 7% higher than Q4/05;
- Increased monthly distributions by 20% to $0.18 per unit from $0.15 per unit;
- Maintained a conservative payout ratio of 53%;
- Commenced the listing of Baytex trust units on the New York Stock Exchange; and
- Generated a total return of 17% to unitholders in the quarter.

Financial		**Three Months Ended**	
($ thousands, except per unit amounts)	**March 31, 2006**	December 31, 2005	March 31, 2005
			(restated - note 3)
Petroleum and natural gas sales	**136,231**	162,356	111,275
Cash flow from operations(1)	**69,748**	65,487	44,540
Per unit - basic	**0.99**	0.95	0.67
- diluted	**0.90**	0.86	0.64
Cash distributions	**36,768**	28,582	29,321
Per unit	**0.54**	0.45	0.45
Net income (loss)	**28,879**	35,184	(11,611)
Per unit - basic	**0.41**	0.51	(0.17)
- diluted	**0.39**	0.47	(0.17)
Exploration and development	**44,886**	31,046	28,465
Net acquisitions (dispositions)	**(570)**	(47,477)	(91)
Total capital expenditures	**44,316**	(16,431)	28,374
Long-term notes	**210,015**	209,799	217,663
Convertible debentures	**42,989**	73,766	-
Bank loan	**124,107**	123,588	190,270
Other working capital deficiency	**25,139**	16,506	20,013
Notional marked-to-market liabilities (assets)	**1,435**	(5,183)	41,826
Total net debt	**403,685**	418,476	469,772
Operating			
Daily production			
Light oil & NGL (bbl/d)	**4,089**	4,022	3,876
Heavy oil (bbl/d)	**21,134**	24,051	21,279
Total oil (bbl/d)	**25,223**	28,073	25,155
Natural gas (MMcf/d)	**60.6**	58.9	59.5
Oil equivalent (boe/d @ 6:1)	**35,319**	37,895	35,068
Average prices (before hedging)			
WTI oil (US$/bbl)	**63.48**	60.02	49.84
Edmonton par oil ($/bbl)	**68.99**	71.18	61.44
BTE light oil & NGL ($/bbl)	**51.33**	55.78	46.69
BTE heavy oil ($/bbl)	**37.87**	37.75	30.83
BTE total oil ($/bbl)	**40.05**	40.33	33.27
BTE natural gas ($/Mcf)	**8.36**	10.69	6.69
BTE oil equivalent ($/boe)	**42.94**	46.48	35.21

	Three Months Ended		
	March 31, 2006	December 31, 2005	March 31, 2005
Trust Unit Information			
TSX (C$)			
Unit Price			
High	**$ 20.90**	$18.78	$15.70
Low	**$ 16.81**	$14.13	$12.42
Close	**$ 20.21**	$17.70	$14.91
Volume traded (thousands)	**24,430**	21,534	26,410
NYSE (US$)(2)			
Unit Price			
High	**$ 17.90**	N/A	N/A
Low	**$ 16.99**	N/A	N/A
Close	**$ 17.37**	N/A	N/A
Volume traded (thousands)	**736**	N/A	N/A
Units outstanding (thousands)(3)	**74,217**	71,475	69,075
Foreign ownership	**34%**	33%	32%

(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. 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) Baytex Energy Trust commenced trading on the NYSE on March 27, 2006; data reflects the period March 27, 2006 to March 31, 2006.

(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.

MESSAGE TO UNITHOLDERS

Operations Review

Production for the first quarter in 2006 averaged 35,319 boe/d, in line with the 35,000 boe/d of average production targeted by Baytex for calendar 2006. Production in the quarter was less than the 37,895 boe/d reported for the fourth quarter of 2005 mainly due to the disposition of approximately 2,000 bbl/d of SAGD (steam-assisted gravity drainage) production at the end of last year.

Capital expenditures for the quarter totaled $44.3 million. During this period, Baytex participated in the drilling of 46 (41.2 net) wells, resulting in 27 (25.1 net) oil wells, 12 (9.1 net) gas wells, three (3.0 net) stratigraphic test wells and four (4.0 net) dry holes. Overall drilling success rate was 91.3% (90.3% net).

At Celtic, Baytex began to realize on the exploitation upside of these assets acquired last year. Average production in the first quarter nearly doubled the 1,750 boe/d purchased in September 2005. Five oil wells were drilled in this area during the first quarter, with another 20 to 25 wells planned for the remainder of the year. At Seal, two horizontal production wells and three stratigraphic test wells were drilled this winter to further delineate the western land block. Baytex is currently focusing on improving marketing arrangements for production from this area and plans to conduct an active development program in Seal once these marketing issues have been resolved.

At Stoddart, three wells were drilled in the first quarter resulting in two gas wells and one dry hole. Production in the first quarter averaged 4,400 boe/d compared to 3,200 boe/d in the same period last year. Four new drills are planned for later this year, together with a number of recompletion projects. Baytex continues to grow its operations in this area with additional land and seismic activities. Natural gas drilling was also conducted in Baytex's winter-access areas of Goodfish, Nina, Foxglove and Hamburg. Overall, Baytex was able to essentially complete its planned capital programs despite a short winter season and a tight oilfield service environment.

Financial Review

Unusually warm winter weather throughout North America has driven natural gas prices sharply lower thus far in 2006. The average wellhead gas price of $8.36 per Mcf in the first quarter was 22% lower than that of the previous quarter. Nevertheless, continued strength in oil prices and the expiry of lower price WTI derivative contracts combined to generate record cash flow of $69.7 million for Baytex in the first quarter of 2006.

Cash flow in the first quarter was also affected by wide heavy oil differentials with Lloyd Blend differentials averaging 46% of WTI price. However, higher seasonal demand and new pipeline capacity transporting Canadian heavy crude to the U.S. lower midwest region have combined to significantly reduce differentials. Baytex is currently projecting an average differential of 30% of WTI in the second quarter of 2006, thereby improving cash flow from production not dedicated to the Frontier supply agreement.

After maintaining a $0.15 per unit distribution for 28 consecutive months since its inception, Baytex announced a 20% increase in its monthly distribution to $0.18 per unit in January 2006. Backed by strong financial performance, the higher distributions still only resulted in a 53% payout ratio (net of DRIP participation of 4.5%) in the first quarter of 2006, ranking Baytex in the top quartile amongst all oil and gas income trusts.

On March 27, 2006, Baytex commenced the listing of its trust units on the New York Stock Exchange (NYSE). Baytex believes that the NYSE listing will improve the trading liquidity of its units and further enhance future access to the U.S. capital markets.

Subsequent to the end of the first quarter, Baytex's bank facilities have been increased to $300 million from $250 million, reflecting the increase in the underlying value of its reserves base. The Bank of Nova Scotia and Societe Generale have agreed to join the banking syndicate providing the facilities. As at March 31, 2006, Baytex had $124.1 million of outstanding borrowings from these facilities.

The outlook for the remainder of the year is very positive for Baytex. Current benchmark oil prices are substantially higher than the first quarter average. Heavy oil differentials are improving due to fundamental changes. Natural gas prices will likely stay volatile through the summer season but should trend higher towards the winter. With a stable production profile underpinned by abundant internal development opportunities, Baytex should continue to generate excellent financial results in 2006.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
May 8, 2006

Management's discussion and analysis ("MD&A"), dated May 8, 2006, should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2006 and the audited consolidated financial statements and MD&A for the year ended December 31, 2005. 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 is not a measure based on generally accepted accounting principles ("GAAP"), but is a financial term commonly used in the oil and gas industry. It represents 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 measure as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions and capital investments.

Production

Light oil and NGL production for the first quarter of 2006 increased by 6% to 4,089 bbl/d from 3,876 bbl/d a year earlier. Heavy oil production was relatively unchanged at 21,134 bbl/d for the first quarter of 2006 compared to 21,279 bbl/d a year ago. Natural gas production increased by 2% to 60.6 MMcf/d for the first quarter of 2006 compared to 59.5 MMcf/d for the same period last year.

Revenue

Petroleum and natural gas sales increased 22% to $136.2 million for the first quarter of 2006 from $111.3 million for the same period in 2005. For the per sales unit calculations, heavy oil sales for the three months ended March 31, 2006 were 68 bbl/d lower (three months ended March 31, 2005 - 51 bbl/d higher) than the production for the period due to inventory in transit under the Frontier supply agreement.

Revenue from light oil and NGL for the first quarter of 2006 increased 16% from the same period a year ago due to a 6% increase in production and a 10% increase in wellhead prices. Revenue from heavy oil increased 21% mainly due to a 23% increase in wellhead prices. Revenue from natural gas increased 27% as a result of a 25% increase in wellhead prices and a 2% increase in production. *(Table 1)*

Royalties

Total royalties increased to $18.1 million for the first quarter of 2006 from $16.6 million in 2005. This increase is reflective of the increase in total revenue. Total royalties for the first quarter of 2006 were 13.3% of sales compared to 14.9% of sales for the same period in 2005. For the first quarter of 2006, royalties were 14.4% of sales for light oil and NGL, 9.4% for heavy oil and 18.9% for natural gas. These rates compared to 13.7%, 11.3% and 21.4%, respectively, for the same period last year.

Table 1.

	Three Months Ended March 31			
	2006		2005	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**18,890**	**51.33**	16,285	46.69
Heavy oil	**71,792**	**37.87**	59,194	30.83
Derivative contracts gain (loss)	**143**	**0.08**	(6,642)	(3.46)
Total oil revenue	**90,825**	**40.12**	68,837	30.34
Natural gas revenue (Mcf)	**45,549**	**8.36**	35,797	6.69
Total revenue (boe @ 6:1)	**136,374**	**42.99**	104,634	33.10

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

Gain (Loss) On Financial Derivatives
Under the CICA 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 where outstanding contracts are marked to market at each month end, and the change in value recorded as unrealized gain or loss. As the contracts come to the end of their terms, the gain or loss is realized.

Derivative contracts yielded a gain of $0.1 million in the first quarter of 2006 compared to a loss of $6.6 million for the same period in the prior year. Derivative contracts outstanding at March 31 2006 were marked to market with an unrealized loss of $6.6 million.

Operating Expenses
Operating expenses for the first quarter of 2006 increased to $27.7 million from $25.6 million in the corresponding quarter last year. Operating expenses were $8.74 per boe for the first quarter of 2006 compared to $8.11 per boe for the first quarter of 2005. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services. For the first quarter of 2006, operating expenses were $8.50 per barrel of light oil and NGL, $9.52 per barrel of heavy oil and $1.20 per Mcf of natural gas. The operating expenses for the same period a year ago were $10.53, $8.59 and $1.02, respectively.

Transportation Expenses
Transportation expenses for the first quarter of 2006 were $5.7 million compared to $5.5 million for the first quarter of 2005. These expenses were $1.79 per boe for the first quarter of 2006 compared to $1.73 for the same period in 2005. Transportation expenses were $2.21 per barrel of oil and $0.13 per Mcf of natural gas. The corresponding amounts for 2005 were $2.07 and $0.14, respectively.

General and Administrative Expenses
General and administrative expenses for the first quarter of 2006 increased to $4.7 million from $3.7 million in 2005. On a per sales unit basis, these expenses were $1.49 per boe for the first quarter of 2006 compared to $1.16 per boe for the same period in 2005. In accordance with our full cost accounting policy, no expenses were capitalized in either the first quarter of 2006 or 2005.

Unit-Based Compensation Expense
Compensation expense related to the Trust's unit rights incentive plan was $1.7 million for the first quarter of 2006 compared to $1.3 million for the first quarter of 2005. 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 Expense
Interest expense increased to $8.8 million for the first quarter of 2006 from $7.0 million for the same quarter last year, primarily due to the general increase in interest rates and the issuance of the 6.5% convertible debentures in June 2005.

Foreign Exchange
Foreign exchange in the first quarter of 2006 was a loss of $0.2 million compared to a loss of $1.1 million in the prior year. The loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8568 at March 31, 2006 compared to 0.8577 at December 31, 2005. The 2005 loss is based on translation at 0.8267 at March 31, 2005 compared to 0.8308 at December 31, 2004.

Depletion, Depreciation and Accretion
The provision for depletion, depreciation and accretion for the first quarter of 2006 has decreased to $38.2 million from $43.3 million for the same quarter a year ago despite higher production. This decrease is due to a lower depletion rate resulting from low-cost proved reserves added from the Celtic acquisition and development activities during 2005. On a sales-unit basis, the provision for the current quarter was $12.03 per boe compared to $13.69 per boe for the same quarter in 2005.

Income Taxes

Current tax expenses increased to $2.2 million for the first quarter of 2006 from $2.0 million for the same quarter a year ago. The current tax expense is comprised of $1.8 million of Saskatchewan Capital Tax and $0.4 million of Large Corporation Tax compared to $1.5 million and $0.5 million, respectively, in the corresponding period in 2005.

Net Income

Net income for the first quarter of 2006 was $28.9 million compared to a loss of $11.6 million for the first quarter in 2005. The variance was the result of higher production and higher sales prices, combined with lower unrealized loss on financial derivatives and lower depletion expense. This was partially offset by higher operating costs and a decrease in future tax recovery.

Liquidity and Capital Resources

At March 31, 2006, total net debt excluding notional marked-to-market assets or liabilities was $402.3 million compared to $423.7 million at the end of 2005. Borrowings under Baytex's bank facilities were $124.1 million, with the capacity of the facilities set at $250 million. The bank facilities have been increased to $300 million subsequent to the end of the first quarter. As at March 31, 2006, $55.1 million principal amount of the 6.5% convertible debentures (original issue at $100 million) had been tendered for conversion into trust units.

Capital Expenditures

The Trust's total capital expenditures are summarized as follows:

	Three Months Ended March 31	
($ thousands)	**2006**	2005
Land	**3,310**	1,205
Seismic	**199**	520
Drilling and completion	**32,440**	21,473
Equipment	**8,770**	4,286
Other	**167**	981
Total exploration and development	**44,886**	28,465
Property dispositions	**(570)**	(91)
Net capital expenditures	**44,316**	28,374

CONSOLIDATED BALANCE SHEETS

(thousands) (unaudited)	**March 31, 2006**	December 31, 2005
Assets		
Current assets		
Accounts receivable	**$ 68,905**	$ 73,869
Crude oil inventory	**9,843**	9,984
Financial derivative contracts *(note 12)*	**-**	5,183
	78,748	89,036
Deferred charges and other assets	**6,532**	9,038
Petroleum and natural gas properties	**976,456**	969,738
Goodwill	**37,755**	37,755
	$ 1,099,491	$ 1,105,567
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 90,932**	$ 89,966
Distributions payable to unitholders	**12,955**	10,393
Bank loan	**124,107**	123,588
Financial derivative contracts *(note 12)*	**1,435**	-
	229,429	223,947
Long-term debt *(note 4)*	**210,015**	209,799
Convertible debentures *(note 5)*	**42,989**	73,766
Asset retirement obligations *(note 6)*	**33,083**	33,010
Deferred obligations *(note 13)*	**4,016**	4,558
Future income taxes	**153,186**	159,745
	672,718	704,825
Non-controlling interest *(note 8)*	**12,987**	12,810
Unitholders' Equity		
Unitholders' capital *(note 7)*	**591,634**	555,020
Conversion feature of debentures *(note 5)*	**2,150**	3,698
Contributed surplus	**10,747**	10,332
Accumulated distributions	**(306,492)**	(267,986)
Accumulated income	**115,747**	86,868
	413,786	387,932
	$ 1,099,491	$ 1,105,567

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

	Three Months Ended March 31	
(thousands, except per unit data) (unaudited)	**2006**	2005
		(restated - note 3)
Revenue		
Petroleum and natural gas sales	**$ 136,231**	$ 111,275
Royalties	**(18,065)**	(16,578)
Realized gain (loss) on financial derivatives	**143**	(6,642)
Unrealized gain (loss) on financial derivatives	**(6,617)**	(32,313)
	111,692	55,742
Expenses		
Operating	**27,720**	25,638
Transportation	**5,694**	5,470
General and administrative	**4,734**	3,655
Unit-based compensation *(note 9)*	**1,731**	1,292
Interest *(note 10)*	**8,786**	7,046
Foreign exchange loss	**216**	1,080
Depletion, depreciation and accretion	**38,167**	43,279
	87,048	87,460
Income (loss) before income taxes and non-controlling interest	**24,644**	(31,718)
Income taxes (recovery)		
Current	**2,159**	1,967
Future	**(6,592)**	(21,757)
	(4,433)	(19,790)
Income (loss) before non-controlling interest	**29,077**	(11,928)
Non-controlling interest *(note 8)*	**(198)**	317
Net income (loss)	**28,879**	(11,611)
Accumulated income, beginning of period, as previously reported	**86,868**	5,694
Accounting policy change for unit based compensation *(note 3)*	**-**	1,298
Accumulated income, beginning of period, as restated	**86,868**	6,992
Accumulated income (deficit), end of period	**$ 115,747**	$ (4,619)
Net income (loss) per trust unit		
Basic	**$ 0.41**	$ (0.17)
Diluted	**$ 0.39**	$ (0.17)
Weighted average trust units		
Basic	**70,664**	66,614
Diluted	**77,853**	69,736

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended March 31		
(thousands) (unaudited)		**2006**		2005
				(restated - note 3)
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**$**	**28,879**	$	(11,611)
Items not affecting cash:				
Unit-based compensation *(note 9)*		**1,731**		1,292
Amortization of deferred charges		**449**		261
Foreign exchange loss		**216**		1,080
Depletion, depreciation and accretion		**38,167**		43,279
Accretion on debentures		**83**		-
Unrealized loss on financial derivatives *(note 12)*		**6,617**		32,313
Future income tax recovery		**(6,592)**		(21,757)
Non-controlling interest *(note 8)*		**198**		(317)
		69,748		44,540
Change in non-cash working capital		**914**		(17,005)
Asset retirement expenditures		**(407)**		(972)
Decrease in deferred charges and other assets		**(489)**		(472)
		69,766		26,091
Financing Activities				
Increase in bank loan		**519**		28,826
Payments of distributions		**(33,715)**		(29,398)
Issue of trust units		**2,590**		1,103
		(30,606)		531
Investing Activities				
Petroleum and natural gas property expenditures		**(44,886)**		(28,465)
Proceeds on disposal of petroleum and natural gas properties		**570**		91
Change in non-cash working capital		**5,156**		1,752
		(39,160)		(26,622)
Change in cash and short-term investments		**-**		-
Cash and short-term investments, beginning of period		**-**		-
Cash and short-term investments, end of period	**$**	**-**	$	-

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Three Months Ended March 31, 2006 and 2005 (all tabular amounts in thousands, except per unit amounts) (unaudited)

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 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, 2005. 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, 2005.

3. CHANGE IN ACCOUNTING POLICY

Unit-based Compensation

Prior to July 1, 2005, the Trust accounted for stock based compensation based on the intrinsic value of the grants at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing unit rights using the fair value based method. In the fourth quarter of 2005, the Trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

As a result of retroactively adopting the fair value method of estimating compensation expense, net loss in the first three months of 2005 was reduced by $5.2 million, net of non-controlling interest of $0.1 million. Net loss per unit changed from $0.25 to $0.17. The opening 2005 accumulated income was increased by $1.3 million, net of non-controlling interest of $0.1 million. Accordingly, the opening 2005 contributed surplus was also decreased by $1.2 million. There was a $0.07 million decrease in the 2005 opening balance of unitholders' capital relating to the transfer of value from contributed surplus on exercise of unit rights in 2004. There was no impact on cash flow as a result of adopting this policy.

4. LONG-TERM DEBT

	March 31, 2006	December 31, 2005
10.5% senior subordinated notes (US$247)	**$ 288**	$ 288
9.625% senior subordinated notes (US$179,699)	**209,727**	209,511
	$ 210,015	$ 209,799

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. Issue costs are being amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. 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.

Issued, June 6, 2005	$	100,000
Fair value of conversion feature		(4,800)
Conversion of debentures and amortization of discount		(21,434)
Balance, December 31, 2005		73,766
Conversion of debentures and amortization of discount		(30,777)
Balance, March 31, 2006	$	42,989

6. ASSET RETIREMENT OBLIGATIONS

		Three Months Ended March 31, 2006		Year Ended December 31, 2005
Balance, beginning of period	**$**	**33,010**	$	73,297
Liabilities incurred		**496**		406
Liabilities settled		**(407)**		(1,637)
Acquisition of liabilities		**-**		3,410
Disposition of liabilities		**(481)**		(2,117)
Accretion		**649**		5,762
Change in estimate		**(184)**		(46,111)
Balance, end of period	**$**	**33,083**	$	33,010

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. These costs are expected to be incurred over the next 52 years with the majority of costs incurred between 2044 and 2057. The undiscounted amount of estimated cash flow required to settle the retirement obligations at March 31, 2006 is $220 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 2.5 percent for the years 2006 to 2008, and 1.5 percent thereafter.

7. UNITHOLDERS' CAPITAL

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

	Number of units	Amount
Balance, December 31, 2004	66,538	$ 515,663
Issued on conversion of debentures	1,549	22,859
Issued on conversion of exchangeable shares	363	5,373
Issued on exercise of trust unit rights[1]	369	4,217
Issued pursuant to distribution reinvestment program	464	6,908
Balance, December 31, 2005	69,283	555,020
Issued on conversion of debentures	2,188	30,402
Issued on conversion of exchangeable shares	4	76
Issued on exercise of trust unit rights[1]	372	3,907
Issued pursuant to distribution reinvestment program	124	2,229
Balance, March 31, 2006	71,971	$ 591,634

(1) Includes compensation expense transferred from contributed surplus.

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 March 31, 2006 was 1.40894 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 to the non-controlling interest on the balance sheet.

	Number of exchangeable shares	Amount
Balance, December 31, 2004 *(restated – note 3)*	1,876	$ 12,936
Exchanged for trust units	(279)	(1,975)
Non-controlling interest in net income	-	1,849
Balance, December 31, 2005	1,597	12,810
Exchanged for trust units	(3)	(21)
Non-controlling interest in net income	-	198
Balance, March 31, 2006	1,594	$ 12,987

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 incentive rights will make new grants available 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.

The Trust recorded compensation expense of $1.7 million for the first three months in 2006 ($1.3 million in 2005) pursuant to rights granted under the Plan (note 3).

Effective January 1, 2006, the Trust has commenced using the binomial-lattice model to calculate the estimated fair value of the unit rights issued.

The following assumptions were used to arrive at the estimate of fair values:

	2006	2005
Expected annual reduction to exercise price	**$2.16**	$1.80
Expected volatility	**23%**	23%
Risk-free interest rate	**3.5%**	3.7%
Expected life of right (years)	**Various (up to 5 years)**	5

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

	Number of rights	**Weighted average exercise price**(1)
Balance, December 31, 2004	3,537	$ 9.60
Granted	2,451	$ 15.01
Exercised	(369)	$ 7.90
Cancelled	(253)	$ 9.83
Balance, December 31, 2005	5,366	$ 10.88
Granted	363	$ 17.67
Exercised	(372)	$ 6.97
Cancelled	(117)	$ 10.51
Balance, March 31, 2006	5,240	$ 11.09

(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 March 31, 2006:

Range of Exercise Prices	Number Outstanding at March 31, 2006	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at March 31, 2006	Weighted Average Exercise Price
$ 4.87 to $ 8.50	1,591	2.5	$ 6.07	887	$ 6.06
$ 8.51 to $12.50	1,364	3.8	$ 10.53	317	$ 9.97
$12.51 to $16.50	1,920	4.6	$ 12.49	12	$ 12.64
$16.51 to $19.72	365	4.8	$ 17.16	-	-
$ 4.87 to $19.72	5,240	3.8	$ 11.09	1,216	$ 7.15

10. INTEREST EXPENSE

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

	Three Months Ended March 31	
	2006	2005
Bank loan	**$ 1,942**	$ 2,244
Amortization of deferred charge	**449**	261
Long-term debt	**6,395**	4,541
Total interest	**$ 8,786**	$ 7,046

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31	
	2006	2005
Interest paid	**$ 12,814**	$ 11,434
Income taxes paid	**$ 1,621**	$ 1,847

12. FINANCIAL DERIVATIVE CONTRACTS

At March 31, 2006, the Trust had derivative contracts for the following:

Oil	**Period**	**Volume**	**Price**	**Index**
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI

Foreign Currency	**Period**	**Amount**	**Floor**	**Cap**
Collar	Calendar 2006	US$3,000,000 per month	CAD$/US$1.1700	CAD$/US$1.2065
Collar	February 1, 2006 to December 31, 2006	US$4,000,000 per month	CAD$/US$1.1500	CAD$/US$1.1835
Collar	January 9, 2006 to December 31, 2006	US$3,000,000 per month	CAD$/US$1.1500	CAD$/US$1.1780

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

Under the CICA 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.

Subsequent to March 31, 2006, the Company entered into derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2007	2,000 bbl/d	US$60.00 – $80.40	WTI
Price collar	Calendar 2007	1,000 bbl/d	US$60.00 – $80.60	WTI

13. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

At March 31, 2006, the Trust had natural gas physical sales contracts with third parties as follows:

Gas	Period	Volume	Price
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 - $10.50
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 - $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 - $12.60

At March 31, 2006 the Trust had operating lease and transportation obligations as detailed below:

		Payments Due Within				
($ thousands)	Total	1 year	2 years	3 years	4 years	5 years
Operating leases	7,712	1,621	1,955	1,985	1,985	166
Transportation agreements	3,009	1,733	1,099	177	-	-
Total	10,721	3,354	3,054	2,162	1,985	166

At March 31, 2006, there are outstanding letters of credit aggregating $7.2 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 recorded as a deferred obligation and is being drawn down over the life of the obligations which continue until October 31, 2008 and which, at March 31, 2006, is recorded at $4,016.

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.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl
Chairman
Baytex Energy Trust
Independent Businessman

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W. A. Blake Cassidy
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Naveen Dargan
Independent Businessman

R.E.T. (Rusty) Goepel
Senior Vice President
Raymond James Ltd.

Dale O. Shwed
President and CEO
Crew Energy Inc.

OFFICERS

Raymond T. Chan
President and CEO

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

Shannon M. Gangl
Secretary
Partner
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Union Bank of California
National Bank of Canada
Royal Bank of Canada
The Bank of Nova Scotia
Societe Generale

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS
Sproule Associates Limited

TRANSFER AGENT
Valiant Trust Company

EXCHANGE LISTING
Toronto Stock Exchange
Unit Symbol: **BTE.UN**
Debenture: **BTE.DB**

New York Stock Exchange
Unit Symbol: **BTE**

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
Mbbls	thousand barrels
MMbbls	million barrels
Mboe	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGL	natural gas liquids

ADVISORY
Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company 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 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 the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. 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.