Q2

BAYTEX

ENERGY TRUST

SECOND QUARTER REPORT

for the three months and six months ended June 30, 2005

HIGHLIGHTS

Baytex Energy Trust (TSX-BTE.UN) is pleased to announce its operating and financial results for the three months and six months ended June 30, 2005.

Highlights of the second quarter in 2005 include:

- Achieved a second consecutive quarter of record cash flow of $50 million, 12 percent higher than the previous quarter and 35 percent higher than the same quarter last year.
- Reduced payout ratio to 58 percent of cash flow from operations compared to 66 percent in the previous quarter and 76 percent in the same quarter last year.
- Established Stoddart as a major natural gas development area with production commencing from two new wells. Current production in August at Stoddart is approximately 35 percent higher than at the time of acquisition in December 2004.
- Improved financial flexibility by issuing $100 million of convertible debentures.

Financial		Three Months Ended		Six Months Ended	
($ thousands, except per unit amounts)	**June 30, 2005**	March 31, 2005	June 30, 2004	**June 30,2005**	June 30, 2004
Petroleum and natural gas sales	**118,379**	111,275	104,517	**229,654**	200,663
Cash flow from operations [1]	**49,937**	44,540	36,944	**94,477**	75,633
Per unit – basic	**0.75**	0.67	0.57	**1.42**	1.17
– diluted	**0.71**	0.64	0.57	**1.35**	1.16
Cash distributions	**28,823**	29,321	28,237	**58,144**	55,941
Per unit	**0.45**	0.45	0.45	**0.90**	0.90
Net income (loss)	**18,804**	(16,811)	(11,213)	**1,993**	(15,791)
Per unit – basic	**0.28**	(0.25)	(0.18)	**0.03**	(0.25)
– diluted	**0.27**	(0.25)	(0.18)	**0.03**	(0.25)
Exploration and development	**31,586**	28,465	15,975	**60,051**	45,218
Acquisitions – net of dispositions	**847**	(91)	–	**756**	–
Total capital expenditures	**32,433**	28,374	15,975	**60,807**	45,218
Long-term notes	**220,542**	217,663	241,199	**220,542**	241,199
Convertible debentures	**95,255**	–	–	**95,255**	–
Bank loan	**109,267**	190,270	–	**109,267**	–
Other working capital deficiency	**16,916**	20,013	7,315	**16,916**	7,315
Notional mark-to-market liabilities	**30,761**	41,826	31,503	**30,761**	31,503
Total net debt	**472,741**	469,772	280,017	**472,741**	280,017
Operating					
Daily production					
Light oil (bbls/d)	**3,404**	3,876	1,952	**3,639**	2,005
Heavy oil (bbls/d)	**19,653**	21,279	22,927	**20,462**	23,125
Total oil (bbls/d)	**23,058**	25,155	24,879	**24,100**	25,130
Natural gas (mmcf/d)	**59.3**	59.5	57.2	**59.4**	56.6
Oil equivalent (boe/d @ 6:1)	**32,937**	35,068	34,411	**33,996**	34,560

	Three Months Ended			Six Months Ended	
	June 30, 2005	March 31, 2005	June 30, 2004	**June 30, 2005**	June 30, 2004
Average prices (before hedging)					
WTI oil (US$/bbl)	**53.17**	49.84	38.32	**51.51**	36.73
Edmonton par oil ($/bbl)	**65.76**	61.44	50.59	**63.60**	48.09
BTE light oil ($/bbl)	**53.06**	46.69	47.55	**49.68**	45.47
BTE heavy oil ($/bbl)	**35.71**	30.83	29.21	**33.18**	27.75
BTE total oil ($/bbl)	**38.27**	33.27	30.63	**35.67**	29.16
BTE natural gas ($/mcf)	**7.08**	6.69	6.61	**6.88**	6.52
BTE oil equivalent ($/boe)	**39.53**	35.21	33.12	**37.31**	31.88
Trust Unit Information					
Unit Price					
High	**$ 15.20**	$ 15.70	$ 12.60	**$ 15.70**	$ 12.60
Low	**$ 12.71**	$ 12.42	$ 12.32	**$ 12.42**	$ 9.78
Close	**$ 13.48**	$ 14.91	$ 12.00	**$ 13.48**	$ 12.00
Units Traded (thousands)	**17,403**	26,410	21,983	**43,813**	56,761
Units Outstanding (thousands) (2)	**69,264**	69,075	62,783	**69,264**	62,783
Foreign Ownership	**32%**	32%	31%	**32%**	31%

(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) 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

Heavy oil operations during the second quarter were significantly hampered by extreme weather conditions in most of Baytex's operating areas. Record rainfall caused widespread flooding in many parts of Alberta and Saskatchewan, limiting the trucking of oil production from well sites to sales terminals. Unfavourable road conditions delayed the deployment of equipment to complete many of the 29 heavy oil wells drilled in the quarter. Similarly, routine workover and maintenance operations were curtailed with both production volume and operating cost efficiency negatively affected.

As a result, Baytex's heavy oil production for the second quarter of 2005 averaged 19,653 bbl/d, eight percent below that of the previous quarter. With improving weather and road conditions thus far in the summer, current production has recovered to approximately 20,500 bbl/d. Baytex will continue to increase its heavy oil production during the second half of 2005.

At Seal, production averaged 805 bbl/d during the second quarter at an average sales price (net of trucking expenses) of $17.27 per barrel. This compares to the corporate sales price (net of trucking) of $33.22 per barrel in the same period. Baytex is continuing to investigate various marketing alternatives. Large scale development at Seal will commence once a marketing arrangement which provides higher wellhead price realization is secured.

Natural Gas production was essentially unchanged at 59.3 mmcf/d in the second quarter of 2005 compared to 59.5 mmcf/d in the previous quarter. At Stoddart, two wells drilled in March and April were put on production in mid-June. Current production from this area totals 4,500 boe/d compared to 3,300 boe/d at the time of acquisition in December 2004. Baytex plans to drill five new wells at Stoddart in the second half of 2005, together with a similar number of recompletions. At Leahurst in central Alberta, Baytex is currently completing its first program of 12 wells for Horseshoe Canyon coalbed methane (CBM) production. The production performance of these wells will help determine future development plans for CBM production. Baytex is excited about the growing ability of its in-house inventory of prospects to sustain its natural gas and light oil production.

Exploration and development capital expenditures in the second quarter totaled $31.6 million. During this period, Baytex participated in the drilling of 37 (35.3 net) wells, resulting in 29 (28.8 net) oil wells, six (4.5 net) gas wells and two (2.0 net) dry holes for an overall success rate of 94.6 percent (94.3 percent net). In addition, one well was drilled through farm-out arrangement at no cost to Baytex.

Baytex was successful in holding its operating costs to $8.07 per boe in the second quarter of 2005 compared to $8.11 per boe in the first quarter. Cost pressure in the industry brought on by high commodity prices and record activity levels is increasing rapidly for both operating and capital expenditures. Nonetheless, in this environment for oilfield goods and services, Baytex will strive to control its costs of doing business through efficiency improvements in its operations.

FINANCIAL REVIEW

Cash flow from operations of $50 million for the second quarter represents yet another record for the Trust, up 12 percent from the previous record set in the first quarter of 2005. This record cash flow was achieved despite the temporary loss of six percent in production as described earlier. On a quarter-over-quarter basis, Baytex's wellhead oil price increased by 15 percent and wellhead gas price increased by six percent. The oil price increase was attributable to a seven percent increase in WTI price and a reduction in the relative cost of diluent for heavy oil blending. Condensate prices in the second quarter averaged 12 percent higher than Edmonton par crude oil price, compared to a 26 percent premium in the first quarter. Lloyd Blend heavy oil differentials were similar during the first two quarters of 2005, with the average differential at 41 percent of WTI price in the second quarter compared to 40 percent in the first quarter. The impact from the volatility of heavy oil differentials on Baytex's cash flow is substantially mitigated by the long-term supply contract with Frontier Oil Corporation, which fixes the differential for approximately 15,500 bbl/d of Baytex's heavy oil sales at 29 percent of WTI price until the end of 2007.

Hedging losses from WTI and foreign exchange collar contracts amounted to $9.8 million in the second quarter of 2005. These contracts expire at the end of 2005 and Baytex currently has not entered into any hedging contracts for 2006.

Baytex completed the issuance of $100 million of 6.5 percent convertible unsecured subordinated debentures in early June 2005. The debentures have a maturity date of December 31, 2010 and are convertible into trust units at a price of $14.75 per unit. Net proceeds from this financing were used to reduce outstanding bank indebtedness, thus substantially improving the financial flexibility of the Trust.

OUTLOOK

Current production is approximately 34,500 boe/d and increasing. Baytex is very encouraged by the growing size and quality of its internal inventory of development prospects, which will lead to positive momentum for production gains heading into 2006. Cash distributions in the second quarter represent a payout ratio of 58 percent which was achieved under an average WTI price of US$53.17, Lloyd Blend differentials of 41 percent, wellhead gas price of $7.08 and realized hedging losses of $9.8 million. The payout ratio in the second half of 2005 should be lower than that of the second quarter due to higher production and stronger prevailing commodity prices. With the hedging contracts set to expire at the end of 2005, the outlook for 2006 is for further improvement in cash flow which will allow Baytex better flexibility in managing its distributions and capital investments.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
August 9, 2005

Management's discussion and analysis ("MD&A"), dated August 9, 2005, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the six months ended June 30, 2005 and the audited consolidated financial statements and MD&A for the year ended December 31, 2004. 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 production for the second quarter of 2005 increased by 74 percent to 3,404 bbl/d from 1,952 bbl/d a year earlier. Heavy oil production decreased 14 percent to 19,653 bbl/d for the second quarter of 2005 compared to 22,927 bbl/d a year ago. Natural gas production increased by 4 percent to 59.3 mmcf/d for the second quarter of 2005 compared to 57.2 mmcf/d for the same period last year. The increase in light oil and natural gas production is due to the acquisitions completed in 2004.

For the first half of 2005, light oil production increased by 82 percent to 3,639 bbl/d from 2,005 bbl/d for the same period last year. Heavy oil production for the first six months of 2005 was down 12 percent to 20,462 bbl/d compared to 23,125 bbl/d for the same period in 2004. Natural gas production increased by 5 percent to average 59.4 mmcf/d for the first six months of 2005 compared to 56.6 mmcf/d for 2004. The increase in light oil and natural gas production is due to the acquisitions completed in 2004.

REVENUE

Petroleum and natural gas sales increased 13 percent to $118.4 million for the second quarter of 2005 from $104.5 million for the second quarter of 2004. For the first six months, petroleum and natural gas sales increased by 14 percent to $229.7 million in 2005 from $200.7 million a year earlier.

For the per sales unit calculations, heavy oil sales for the three months ended June 30, 2005 were 31 barrels per day lower (three months ended June 30, 2004 – 266 barrels per day higher) than the production for the period due to inventory in transit under the Frontier supply agreement. The corresponding number for the six months ended June 30, 2005 was an increase of 10 barrels per day (six months ended June 30, 2004 – an increase of 24 barrels per day).

	Three Months ended June 30			
	2005		2004	
	thousands	**$/Unit(1)**	thousands	$/Unit(1)
Oil revenue (barrels)				
Light oil	**$ 16,438**	**53.06**	$ 8,444	47.55
Heavy oil	**63,756**	**35.71**	61,651	29.21
Derivative contracts loss	**(9,797)**	**(5.49)**	(16,416)	(7.17)
Total oil revenue	**70,397**	**33.60**	53,679	23.46
Natural gas revenue (mcf)	**38,185**	**7.08**	34,422	6.61
Total revenue (boe @ 6:1)	**$ 108,582**	**36.26**	$ 88,101	27.92

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

Revenue from light oil for the second quarter of 2005 increased 95 percent from the same period a year ago due to a 74 percent increase in production and a 12 percent increase in wellhead prices. Revenue from heavy oil increased 3 percent as a 14 percent decrease in production was offset by a 22 percent increase in wellhead prices. Revenue from natural gas increased 11 percent as the result of a 7 percent increase in wellhead prices and a 4 percent increase in production.

	Six Months ended June 30					
	2005			2004		
		thousands	**$/Unit[1]**		thousands	$/Unit[1]
Oil revenue (barrels)						
Light oil	$	**32,724**	**49.69**	$	16,590	45.47
Heavy oil		**122,949**	**33.18**		116,920	27.75
Derivative contracts loss		**(16,439)**	**(4.44)**		(25,838)	(5.64)
Total oil revenue		**139,234**	**37.58**		107,672	23.52
Natural gas revenue (mcf)		**73,981**	**6.88**		67,153	6.52
Total revenue (boe @ 6:1)	$	**213,215**	**34.64**	$	174,825	27.78

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

For the first six months of 2005, light oil revenue increased 97 percent from the same period last year due to a 9 percent increase in wellhead prices and an 81 percent increase in production. Revenue from heavy oil increased 5 percent due to a 20 percent increase in wellhead prices partially offset by a 12 percent decrease in production. Revenue from natural gas increased 10 percent compared to the first half of 2004, as production increased 4 percent combined with a price increase of 6 percent.

ROYALTIES

Total royalties decreased to $15.4 million for the second quarter of 2005 from $16.2 million in 2004. Total royalties for the second quarter of 2005 were 13.0 percent of sales compared to 15.5 percent of sales for the same period in 2004. For the second quarter of 2005, royalties were 16.0 percent of sales for light oil, 10.8 percent for heavy oil and 15.4 percent for natural gas. These rates compared to 13.4 percent, 11.8 percent and 22.8 percent, respectively, for the same period last year.

For the six months ended June 30, 2005, royalties increased to $32.0 million from $31.5 million for the same period last year. Total royalties for the first half of 2005 were 13.9 percent of sales, compared to 15.7 percent of sales for the corresponding period a year ago. For the first six months of 2005, royalties were 14.9 percent of sales for light oil, 11.1 percent for heavy oil and 18.3 percent for natural gas. These rates compared to 13.6 percent, 12.3 percent and 22.2 percent, respectively, for the same period in 2004.

OPERATING EXPENSES

Operating expenses for the second quarter of 2005 increased to $24.2 million from $21.4 million in the corresponding quarter last year. Operating expenses were $8.07 per boe for the second quarter of 2005 compared to $6.96 per boe for the second quarter of 2004. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services. For the second quarter of 2005, operating expenses were $9.12 per barrel of light oil, $8.88 per barrel of heavy oil and $1.02 per mcf of natural gas. The operating expenses for the same period a year ago were $9.97, $7.55 and $0.82, respectively.

Operating expenses for the first half of 2005 increased to $49.8 million from $42.7 million for the first half in 2004. Operating expenses were $8.09 per boe for the first six months of 2005 compared to $6.78 per boe for the corresponding period of the prior year. For the first half of 2005, operating expenses were $9.87 per barrel of light oil, $8.73 per barrel of heavy oil and $1.02 per mcf of natural gas versus $9.14, $7.39 and $0.79, respectively, for the same period a year earlier.

TRANSPORTATION EXPENSES

Transportation expenses for the second quarter of 2005 were $5.6 million compared to $4.7 million for the second quarter of 2004. These expenses were $1.89 per boe for the second quarter of 2005 compared to $1.30 for the same period in 2004. Transportation expenses were $2.34 per barrel of oil and $0.14 per mcf of natural gas. The corresponding amounts for 2004 were $1.37 and $0.19, respectively.

Transportation expenses for the six months ended June 30, 2005 were $11.1 million compared to $9.6 million for the first six months of 2004. These expenses were $1.81 per boe in 2005 compared to $1.52 in 2004. Transportation expenses were $2.20 per barrel of oil and $0.14 per mcf of natural gas in the 2005 period, and $1.68 per barrel of oil and $0.19 per mcf of natural gas in the 2004 period.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses for the second quarter of 2005 at $3.9 million remain unchanged from the $3.9 million in 2004. On a per sales unit basis, these expenses were $1.30 per boe for the second quarter of 2005 compared to $1.22 per boe for 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either the second quarter of 2005 or 2004.

General and administrative expenses for the first six months of 2005 were $7.5 million, compared to $7.2 million for the prior year. On a per sales unit basis, these expenses were $1.22 per boe in 2005 and $1.14 per boe in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either 2005 or 2004.

UNIT-BASED COMPENSATION EXPENSE

Compensation expense related to the Trust's unit rights incentive plan was a recovery of $1.0 million for the second quarter of 2005 compared to an expense of $1.7 million for the second quarter of 2004.

For the six months ended June 30, 2005, compensation expense was $5.6 million compared to $3.0 million for the same period in 2004.

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

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

INTEREST EXPENSES

Interest expenses on long-term debt increased to $7.8 million for the second quarter of 2005 from $5.2 million for the same quarter last year, primarily due to the increased debt used to finance acquisitions completed in late 2004, plus a general increase in interest rates.

For the first six months of 2005, interest expenses on long-term debt was $14.8 million compared to $9.0 million for the same period last year. The increase is attributable to the same factors influencing the second quarter variance.

FOREIGN EXCHANGE

The foreign exchange loss in the second quarter of 2005 was $2.9 million compared to a loss of $5.4 million in the prior year. The loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8159 at June 30, 2005 compared to 0.8267 at March 31, 2005. The 2004 loss is based on translation at 0.7460 at June 30, 2004 compared to 0.7631 at March 31, 2004.

The foreign exchange loss for the first six months of 2005 was $4.0 million compared to $8.6 million in the prior year. The 2005 loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8159 at June 30, 2005 compared to 0.8308 at December 31, 2004. The 2004 loss is based on translation at 0.7460 at June 30, 2004 compared to 0.7737 at December 31, 2003.

DEPLETION, DEPRECIATION AND ACCRETION

The provision for depletion, depreciation and accretion increased to $41.5 million for the second quarter of 2005 compared to $39.2 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $13.86 per boe compared to $12.43 per boe for the same quarter in 2004.

Depletion, depreciation and accretion increased to $84.8 million for the first half of 2005 compared to $79.9 million for the same period last year. On a sales-unit basis, the provision for the current period was $13.77 per boe compared to $12.70 per boe for the same period a year earlier.

INCOME TAXES

Current tax expenses were $2.0 million for the second quarter of 2005 compared to $2.6 million for the same quarter a year ago. The current tax expense is comprised of $1.5 million of Saskatchewan Capital Tax and $0.5 million of Large Corporation Tax compared to $1.8 million and $0.8 million, respectively, in the corresponding period in 2004.

Current tax expenses were $4.0 million for the first half of 2005 compared to $4.8 million for the same period last year. The current tax expense is comprised of $3.0 million of Saskatchewan Capital Tax and $0.9 million of Large Corporation Tax compared to $3.2 million and $1.6 million, respectively, in 2004.

NET INCOME

Net income for the second quarter of 2005 was $18.8 million compared to a $11.2 million loss incurred in the second quarter in 2004. The favourable variance was the result of higher sales prices, unrealized gain on the financial derivatives, lower foreign exchange loss, and a recovery on the unit-based compensation expense.

Net income for the first six months of 2005 was $2.0 million compared to a $15.8 million loss for the same period in 2004. The variance was primarily due to higher sales revenue and lower loss in financial derivatives for the 2005 period.

LIQUIDITY AND CAPITAL RESOURCES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5 percent 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 net proceeds were used to reduce outstanding bank indebtedness.

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 will be 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.

At June 30, 2005, total net debt (including working capital) was $472.7 million compared to $280.0 million at June 30, 2004 and $422.0 million at December 31, 2004. The increase from June 30, 2004 was primarily due to the financing of acquisitions made in the second half of 2004. The June 30, 2005 net debt balance included $30.8 million of notional liabilities based on the mark-to-market valuations of derivative contracts as at June 30, 2005.

CAPITAL EXPENDITURES

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

	Six Months ended June 30	
(thousands)	**2005**	2004
Land	**$ 4,007**	$ 4,108
Seismic	**1,359**	517
Drilling and completion	**42,225**	26,767
Equipment	**10,359**	12,324
Other	**2,101**	1,502
Total exploration and development	**60,051**	45,218
Property acquisitions	**948**	–
Property dispositions	**(192)**	–
Net capital expenditures	**$ 60,807**	$ 45,218

(thousands) (unaudited)	**June 30, 2005**	December 31, 2004
Assets		
Current assets		
Accounts receivable	**$ 58,557**	$ 41,154
Crude oil inventory	**8,624**	7,299
	67,181	48,453
Deferred charges and other assets	**10,412**	6,491
Petroleum and natural gas properties	**998,365**	1,009,933
Goodwill *(note 4)*	**37,755**	39,259
	$ 1,113,713	$ 1,104,136
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 74,056**	$ 72,976
Distributions payable to unitholders	**10,041**	9,981
Bank loan	**109,267**	161,444
Financial derivative contracts *(note 14)*	**30,761**	9,513
	224,125	253,914
Long-term debt *(note 5)*	**220,542**	216,583
Convertible debentures *(note 6)*	**95,255**	–
Asset retirement obligations *(note 7)*	**75,431**	73,297
Deferred obligations *(note 8)*	**5,196**	–
Future income taxes	**141,656**	164,909
	762,205	708,703
Non-controlling interest *(note 10)*	**12,399**	12,962
Unitholders' Equity		
Unitholders' capital *(note 9)*	**521,404**	515,728
Conversion feature of debentures *(note 6)*	**4,791**	–
Contributed surplus	**11,773**	7,494
Accumulated distributions	**(206,546)**	(146,445)
Accumulated income	**7,687**	5,694
	339,109	382,471
	$ 1,113,713	$ 1,104,136

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

	Three Months Ended June 30		Six Months Ended June 30	
(thousands, except per unit data) (unaudited)	**2005**	2004	**2005**	2004
		(restated – note 3)		*(restated – note 3)*
Revenue				
Petroleum and natural gas sales	**$ 118,379**	$ 104,517	**$ 229,654**	$ 200,663
Royalties	**(15,434)**	(16,237)	**(32,012)**	(31,528)
Realized loss on financial derivatives	**(9,797)**	(16,416)	**(16,439)**	(25,838)
Unrealized gain (loss) on financial derivatives	**11,066**	(7,109)	**(21,247)**	(21,393)
	104,214	64,755	**159,956**	121,904
Expenses				
Operating	**24,176**	21,384	**49,814**	42,659
Transportation	**5,647**	4,684	**11,117**	9,594
General and administrative	**3,885**	3,853	**7,540**	7,169
Unit-based compensation (recovery) *(note 11)*	**(1,030)**	1,707	**5,607**	2,988
Interest *(note 12)*	**7,848**	5,161	**14,894**	9,033
Foreign exchange loss	**2,879**	5,380	**3,959**	8,637
Depletion, depreciation and accretion	**41,497**	39,220	**84,776**	79,908
	84,902	81,389	**177,707**	159,988
Income (loss) before income taxes and non-controlling interest	**19,312**	(16,634)	**(17,751)**	(38,084)
Income taxes				
Current expense	**2,015**	2,629	**3,982**	4,791
Future recovery	**(2,007)**	(7,711)	**(23,764)**	(26,611)
	8	(5,082)	**(19,782)**	(21,820)
Income (loss) before non-controlling interest	**19,304**	(11,552)	**2,031**	(16,264)
Non-controlling interest *(notes 3 and 10)*	**(500)**	339	**(38)**	473
Net income (loss)	**18,804**	(11,213)	**1,993**	(15,791)
Accumulated income (deficit), beginning of period, as previously reported	**(11,117)**	(12,894)	**5,694**	(8,598)
Accounting policy change for non-controlling interest *(note 3)*	**–**	247	**–**	529
Accumulated income (deficit), beginning of period, as restated	**(11,117)**	(12,647)	**5,694**	(8,069)
Accumulated income (deficit), end of period	**$ 7,687**	$ (23,860)	**$ 7,687**	$ (23,860)
Net income (loss) per trust unit				
Basic	**$ 0.28**	$ (0.18)	**$ 0.03**	$ (0.25)
Diluted	**$ 0.27**	$ (0.18)	**$ 0.03**	$ (0.25)
Weighted average trust units				
Basic	**66,874**	62,734	**66,745**	62,047
Diluted	**71,922**	65,243	**71,017**	65,033

See accompanying notes to the consolidated financial statements.

	Three Months Ended June 30		Six Months Ended June 30	
(thousands) (unaudited)	**2005**	2004	**2005**	2004
		(restated – note 3)		*(restated – note 3)*
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**$ 18,804**	$ (11,213)	**$ 1,993**	$ (15,791)
Items not affecting cash:				
Unit-based compensation (recovery) *(note 11)*	**(1,030)**	1,707	**5,607**	2,988
Amortization of deferred charges	**314**	2,791	**574**	5,582
Foreign exchange loss	**2,879**	5,380	**3,959**	8,637
Depletion, depreciation and accretion	**41,497**	39,220	**84,776**	79,908
Accretion on debenture	**46**	–	**46**	–
Unrealized (gain) loss on financial derivatives *(note 14)*	**(11,066)**	7,109	**21,248**	21,393
Future income tax recovery	**(2,007)**	(7,711)	**(23,764)**	(26,611)
Non-controlling interest *(note 10)*	**500**	(339)	**38**	(473)
Funds flow from operations	**49,937**	36,944	**94,477**	75,633
Change in non-cash working capital	**(208)**	4,015	**(17,213)**	(126)
Asset retirement expenditures	**(50)**	(207)	**(1,022)**	(885)
Decrease (increase) in deferred charges and other assets	**228**	53	**(244)**	106
	49,907	40,805	**75,998**	74,728
Financing Activities				
Issuance of convertible debentures *(note 6)*	**100,000**	–	**100,000**	–
Convertible debentures issue costs *(note 6)*	**(4,250)**	–	**(4,250)**	–
Increase (decrease) in bank loan	**(81,003)**	–	**(52,177)**	–
Payments of distributions	**(29,381)**	(28,224)	**(58,779)**	(55,646)
Issue of trust units	**479**	–	**1,582**	–
	(14,155)	(28,224)	**(13,624)**	(55,646)
Investing Activities				
Petroleum and natural gas property expenditures	**(32,534)**	(15,975)	**(60,999)**	(45,218)
Disposal of petroleum and natural gas properties	**101**	–	**192**	–
Change in non-cash working capital	**(3,319)**	(13,129)	**(1,567)**	(11,587)
	(35,752)	(29,104)	**(62,374)**	(56,805)
Change in cash and short-term investments	**–**	(16,523)	**–**	(37,723)
Cash and short-term investments, beginning of period	**–**	32,531	**–**	53,731
Cash and short-term investments, end of period	**$ –**	$ 16,008	**$ –**	$ 16,008

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

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

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

2. ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2004. 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, 2004.

3. CHANGES IN ACCOUNTING POLICY

Non-controlling Interest

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. The presentation of the exchangeable shares at June 30, 2004 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of unitholders' equity.

As a result of the adoption of EIC 151, net income was reduced in the first six months of 2004 by $0.33 million (three months ended June 30, 2004 – $0.05 million). As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-by-step acquisition where unitholders' capital was increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the six months ended June 30, 2004, the adoption of EIC 151 resulted in a $15.8 million increase in petroleum and natural gas properties (three months ended June 30, 2004 – $0.02 million), a $6.0 million increase in future income taxes (three months ended June 30, 2004 – $0.01 million) and a $10.7 million increase in unitholders' capital (three months ended June 30, 2004 – $0.04 million).

4. CORPORATE ACQUISITION

The Company continues to evaluate the final adjustments related to the acquisition made in 2004. Therefore, the purchase price allocation is subject to change.

Three Months and Six Months Ended June 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

Goodwill of $37.8 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. LONG-TERM DEBT

	June 30, 2005	December 31, 2004
10.5% senior subordinated notes (US$247)	**$ 303**	$ 297
9.625% senior subordinated notes (US$179,699)	**220,239**	216,286
	$ 220,542	$ 216,583

6. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5 percent 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 will be 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 conversion price paid.

Issuance on June 6, 2005	$ 100,000
Portion allocated to equity	(4,791)
Accretion of non-cash interest expense	46
Balance, June 30, 2005	$ 95,255

7. ASSET RETIREMENT OBLIGATIONS

	Six Months Ended	
	June 30, 2005	June 30, 2004
Balance, beginning of period	**$ 73,297**	$ 55,996
Liabilities incurred	**922**	1,729
Liabilities settled	**(1,022)**	(885)
Change in estimate	**(671)**	–
Accretion	**2,905**	2,240
Balance, end of period	**$ 75,431**	$ 59,080

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 June 30, 2005 is $196.0 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

Three Months and Six Months Ended June 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

8. DEFERRED OBLIGATIONS

The Company has future contractual processing obligations with respect to assets acquired. These obligations continue until October 2008.

9. UNITHOLDERS' CAPITAL

Trust Units

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

	Number of units	Amount
Balance, December 31, 2004	66,538	$ 515,728
Issued on conversion of exchangeable shares	107	1,504
Issued on exercise of trust unit rights	199	1,664
Transfer from contributed surplus on exercise of trust unit rights	–	1,246
Issued pursuant to distribution reinvestment program	96	1,262
Balance, June 30, 2005	66,940	$ 521,404

10. 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 of the five day trading period ending on the record date. The exchange ratio at June 30, 2005 was 1.29701 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

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

	Number of exchangable shares	Amount
Balance, December 31, 2004	1,876	$ 12,962
Exchanged for trust units	(85)	(601)
Non-controlling interest in net income	–	38
Balance, June 30, 2005	1,791	$ 12,399

11. TRUST UNIT RIGHTS

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 percent 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, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

Three Months and Six Months Ended June 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

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

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in earnings over the vesting period of the plan. Compensation expense for the unit rights for the second quarter was a recovery of $1.0 million in 2005 (an expense of $1.7 million in 2004) and for the six months ended June 30 was an expense of $5.6 million in 2005 (an expense of $3.0 million in 2004).

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	185	$ 15.53
Exercised	(199)	$ 7.78
Cancelled	(121)	$ 9.14
Balance, June 30, 2005	3,402	$ 9.04

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

12. INTEREST EXPENSE

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

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
Credit facility charges	**$ 2,088**	$ 117	**$ 4,332**	$ 257
Amortization of deferred charge	**314**	264	**575**	527
Long-term debt	**5,446**	4,780	**9,987**	8,249
Total interest	**$ 7,848**	$ 5,161	**$ 14,894**	$ 9,033

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
Interest paid	**$ 1,766**	$ 55	**$ 13,200**	$ 10,553
Income taxes paid	**$ 2,434**	$ 8,201	**$ 4,281**	$ 13,052

Three Months and Six Months Ended June 30, 2005 and 2004 (all tabular amounts in thousands, except per unit amounts) (unaudited)

14. FINANCIAL DERIVATIVE CONTRACTS

At June 30, 2005, the Trust had financial derivative contracts for the following:

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

			Exchange Rate	
Foreign currency	Period	Amount	Floor	Cap
Collar	Calendar 2005	US$2,000,000 per month	CAD/USD $1.2140	CAD/USD $1.2500
Collar	Calendar 2005	US$3,000,000 per month	CAD/USD $1.2200	CAD/USD $1.2500
Collar	Calendar 2005	US$4,000,000 per month	CAD/USD $1.2150	CAD/USD $1.2500

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.

15. RECLASSIFICATION

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

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

Daniel G. Belot
Vice President, Finance and CFO

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

HEAD OFFICE

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: 403-269-4282
Fax: 403-205-3845
Website: www.baytex.ab.ca
Toll-free: 1-800-524-5521

AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: BTE.UN

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
NGLs	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 Trusts'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.

BAYTEX

ENERGY TRUST

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: 403-269-4282
Fax: 403-205-3845
Website: www.baytex.ab.ca
Toll-free: 1-800-524-5521