BAYTEX
ENERGY TRUST

Q2

SECOND QUARTER REPORT
FOR THE SIX MONTHS ENDED JUNE 30, 2004

HIGHLIGHTS

Baytex Energy Trust is pleased to report its operating and financial results for the six months ended June 30, 2004. The Trust commenced operations on September 2, 2003 as a result of the reorganization of Baytex Energy Ltd. As the Trust is considered the successor organization to Baytex Energy Ltd. for reporting purposes, comparative information is provided for the three months and six months ended June 30, 2003. Pursuant to the Plan of Arrangement effecting the reorganization, certain assets were not transferred to the Trust. Accordingly, results of the corresponding periods in 2003 and 2004 are not entirely comparable.

Financial	Three Months Ended			Six Months Ended	
($ thousands, except per unit amounts)	**June 30, 2004**	March 31, 2004	June 30, 2003	**June 30, 2004**	June 30, 2003
Petroleum and natural gas sales	**104,517**	96,146	89,999	**200,663**	214,804
Cash flow from operations [(1)]	**36,944**	38,689	33,372	**75,633**	88,079
Per unit – basic	**0.57**	0.60	0.62	**1.17**	1.65
– diluted	**0.57**	0.60	0.61	**1.16**	1.61
Cash distributions declared	**28,237**	27,704	–	**55,941**	–
Per unit	**0.45**	0.45	–	**0.90**	–
Net income (loss)	**(11,170)**	(4,296)	40,329	**(15,466)**	72,433
Per unit – basic	**(0.17)**	(0.07)	0.75	**(0.24)**	1.36
– diluted	**(0.17)**	(0.07)	0.73	**(0.24)**	1.32
Exploration and development	**15,975**	29,243	53,474	**45,218**	114,686
Acquisitions – net of dispositions	**–**	–	3,239	**–**	(131,711)
Total capital expenditures	**15,975**	29,243	56,713	**45,218**	(17,025)
Long-term notes				**241,199**	203,295
Working capital deficiency				**38,818**	19,828
Total net debt				**280,017**	223,123
Operating					
Daily production					
Light oil (bbls/d)	**1,952**	2,058	2,167	**2,005**	2,566
Heavy oil (bbls/d)	**22,927**	23,322	22,816	**23,125**	23,046
Total oil (bbls/d)	**24,879**	25,380	24,983	**25,130**	25,612
Natural gas (mmcf/d)	**57.2**	56.0	57.5	**56.6**	65.7
Oil equivalent (boe/d @ 6:1)	**34,411**	34,709	34,574	**34,560**	36,566
Average sales prices (before hedging)					
WTI oil (US$/bbl)	**38.32**	35.15	28.91	**36.73**	31.29
Edmonton par oil ($/bbl)	**50.59**	45.59	41.08	**48.09**	46.02
BTE light oil ($/bbl)	**47.55**	43.50	38.24	**45.47**	42.83
BTE heavy oil ($/bbl)	**29.21**	26.29	24.59	**27.75**	28.72
BTE total oil ($/bbl)	**30.63**	27.70	25.80	**29.16**	30.19
BTE natural gas ($/mcf)	**6.61**	6.43	6.21	**6.52**	6.75
BTE oil equivalent ($/boe)	**33.12**	30.63	29.02	**31.88**	33.36
Weighted average units (thousands)					
Basic	**64,933**	64,761	53,515	**64,833**	53,415
Diluted	**65,243**	64,767	54,960	**65,033**	54,752

(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.

OPERATIONS REVIEW

The second quarter is traditionally the least active quarter in the year for the Trust's drilling operations due to field conditions during spring breakup. Weather conditions so far this spring and summer have been less than favourable in the Trust's major operating areas, resulting in a modest capital program of only $16.0 million in the second quarter. During this period, Baytex participated in the drilling of 25 (25.0 net) wells, resulting in 23 (23.0 net) oil wells, one (1.0 net) gas well and one (1.0 net) dry hole. The drilling program's overall success rate was 96 percent. In addition to this program, eight wells were drilled by other operators through farm-in arrangements on Baytex lands, resulting in six cased potential oil and gas wells and two dry holes. The Trust has retained various working or royalty interests in these wells.

According to industry drilling statistics, Baytex Energy Trust ranked as the 20th most active operator in the Province of Alberta and 15th in the Province of Saskatchewan during the first six months of 2004. These high rankings, which are not normally associated with the operations of oil and gas income trusts, demonstrate the strategy of Baytex in maintaining its production and asset base through internally generated opportunities.

Production for the second quarter of 2004 averaged 34,411 boe/d compared to 34,709 boe/d for the first quarter of 2004, despite the expected production interruption caused by road bans during spring breakup. This production level is also superior to that of the second quarter of 2003 as the 34,574 boe/d reported for the same period last year included approximately 1,500 boe/d of production that were transferred to Crew Energy Inc. pursuant to the Plan of Arrangement. This operating performance is achieved entirely through internal property development as Baytex has not completed any acquisitions since the fourth quarter of 2002.

FINANCIAL REVIEW

WTI oil averaged US$38.32 per barrel in the second quarter of 2004, the highest quarterly average on record. The Trust incurred $16.4 million of losses on derivative instruments during the quarter primarily from the 15,000 bbls/d of WTI collar contracts, which prices are capped at the average of US$29.75. These contracts are due to expire on December 31, 2004.

Baytex employs a comprehensive hedging program to safeguard cash flow in order to sustain its cash distributions and capital reinvestments. World geo-political events have kept oil prices at unprecedented levels, inciting varying opinions on the future of oil prices. The Trust has taken advantage of recent market conditions and entered into several WTI costless collar contracts for calendar 2005. These contracts are for an aggregate volume of 8,000 bbls/d, have a floor price of US$35.00 and an average cap price of US$42.55, thus providing significant downside protection to 2005 cash flow while allowing for participation in the benefits of continued high oil prices.

Wellhead prices for heavy oil were negatively affected by heavy oil differentials in the second quarter of 2004. Lloyd blend crude differentials averaged 32 percent during this period, compared to the 28 percent long-term average for the comparable periods. Baytex is substantially sheltered from these volatilities as the fixed differential crude oil supply agreement with Frontier Oil Corporation covers approximately three-quarters of the Trust's heavy oil production volume after royalties. Costs of blending diluents were also very high during this second quarter, with condensate trading at significant premiums over par crude. However, seasonal factors are expected to improve both differentials and diluent costs during the third quarter and early part of the fourth quarter.

Operating expenses averaged $6.78 per boe for the second quarter of 2004, representing the fifth consecutive quarter where these expenses have been maintained at the same level amidst the inflationary environment in the oil and gas sector fuelled by high commodity prices.

	Q2/04	Q1/04	Q4/03	Q3/03	Q2/03
Operating expenses ($/boe)	**6.78**	6.78	6.74	6.75	6.77

General and administrative expenses averaged $1.14 per boe in the first half of 2004. Baytex's overhead cost structure is ranked in the lowest quartile in the oil and gas income trust sector as there were no expenses capitalized and no external management fees paid.

Cash distributions in the first half of 2004 amounted to $55.6 million, representing 74 percent of cash flow from operations. Based on current operating and market conditions, Baytex is comfortable in maintaining its monthly distribution at $0.15 per unit for the balance of 2004, considering that current cash flow is significantly impaired by the crude oil hedging contracts which are due to expire at the end of this year. The Trust incurred a net loss of $15.5 million during the first six months of 2004, entirely due to unrealized losses on derivative contracts and foreign currency translation totalling $35.1 million. The underlying new accounting policies have no impact on cash flow and could cause significant fluctuations in net income due to volatilities in commodity prices and foreign exchange rates.

OUTLOOK

With $60 million of the $105 million capital budget left to be spent in the second half of this year, Baytex will continue to be disciplined in managing its operational and financial activities. The Trust will maintain its approach in evaluating acquisition opportunities to ensure that only beneficial and accretive transactions are considered. In addition to its cash distributions, Baytex trust units have appreciated approximately 15 percent in value so far in 2004, compared to a two percent increase in the S&P/TSX Energy Trust Index. Management and employees at Baytex will continue to focus on delivering superior return to its unitholders.

On behalf of the Board of Directors,

[signed]

Raymond T. Chan, CA
President and Chief Executive Officer
August 9, 2004

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

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

Management's discussion and analysis ("MD&A"), dated August 9, 2004, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the six months ended June 30, 2004 and the audited consolidated financial statements and MD&A for the year ended December 31, 2003. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Cash flow from operations 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 2004 decreased by 10 percent to 1,952 bbls/d from 2,167 bbls/d a year earlier. Heavy oil production increased to 22,927 bbls/d for the second quarter of 2004 compared to 22,816 bbls/d a year ago. Natural gas production decreased to 57.2 mmcf/d for the second quarter of 2004 compared to 57.5 mmcf/d for the same period last year.

For the first half of 2004, light oil production decreased by 22 percent to 2,005 bbls/d from 2,566 bbls/d for the same period last year due to the sale of properties in March 2003 in the Ferrier area. Heavy oil production for the first six months of 2004 was 23,125 bbls/d compared to 23,046 bbls/d for the same period in 2003. Natural gas production decreased by 14 percent to average 56.6 mmcf/d for the first six months of 2004 compared to 65.7 mmcf/d for 2003, also due to the sale of the Ferrier properties.

Revenue

Petroleum and natural gas sales increased 16 percent to \$104.5 million for the second quarter of 2004 from \$90.0 million for the second quarter of 2003. For the first six months, petroleum and natural gas sales decreased by seven percent to \$200.7 million in 2004 from \$214.8 million a year earlier.

For the per-unit calculations, heavy oil sales for the three months ended June 30, 2004 were 266 bbls/d 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, 2004 was 24 bbls/d.

Revenue from light oil for the second quarter of 2004 increased 12 percent from the same period a year ago due to a 10 percent decrease in production and a 24 percent increase in wellhead prices. Revenue from heavy oil increased 23 percent due to an increase in wellhead prices. Revenue from natural gas increased six percent as the seven percent increase in wellhead prices was offset by a one percent decrease in production.

For the first six months of 2004, light oil revenue decreased 17 percent from the same period last year due to a six percent increase in wellhead prices and a 22 percent decrease in production. Revenue from heavy oil increased two percent due to the increase in wellhead prices. Revenue from natural gas decreased 16 percent as wellhead prices decreased three percent and production decreased 14 percent compared to the first half of 2003.

Royalties

Total royalties remained the same at $16.2 million for the second quarter of 2004. Total royalties for the second quarter of 2004 were 15.5 percent of sales compared to 18.0 percent of sales for the same period in 2003. For the second quarter

Revenue

Three Months Ended June 30	2004		2003	
	$000s	$/Unit (1)	$000s	$/Unit (1)
Oil revenue				
Light oil	**8,444**	**47.55**	7,542	38.24
Heavy oil	**61,651**	**29.21**	49,940	24.59
Derivative contracts loss	**(16,416)**	**(7.17)**	(6,379)	(2.86)
Total oil revenue	**53,679**	**23.46**	51,103	22.93
Natural gas revenue	**34,422**	**6.61**	32,517	6.21
Total revenue (boe @ 6:1)	**88,101**	**27.92**	83,620	26.97

Six Months Ended June 30	2004		2003	
	$000s	$/Unit (1)	$000s	$/Unit (1)
Oil revenue				
Light oil	**16,590**	**45.47**	19,888	42.83
Heavy oil	**116,920**	**27.75**	114,630	28.72
Derivative contracts loss	**(25,838)**	**(5.64)**	(19,960)	(4.48)
Total oil revenue	**107,672**	**23.52**	114,558	25.71
Natural gas revenue	**67,153**	**6.52**	80,286	6.75
Total revenue (boe @ 6:1)	**174,825**	**27.78**	194,844	30.26

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

of 2004, royalties were 13.4 percent of sales for light oil, 11.8 percent for heavy oil and 22.8 percent for natural gas. These rates compared to 18.9 percent, 13.7 percent and 24.3 percent, respectively, for the same period last year.

For the six months ended June 30, 2004, royalties decreased 18 percent to $31.5 million from $38.4 million for the same period last year. Total royalties for the first half of 2004 were 15.7 percent of sales, down from 17.9 percent of sales for the corresponding period a year ago due to an increased percentage of total production from heavy oil. For the first six months of 2004, royalties were 13.6 percent of sales for light oil, 12.3 percent for heavy oil and 22.2 percent for natural gas. These rates compared to 18.6 percent, 13.9 percent and 23.4 percent, respectively, for the same period in 2003.

Operating Expenses

Operating expenses for the second quarter of 2004 increased two percent to $21.4 million from $21.0 million in the corresponding quarter last year. Operating expenses were $6.78 per boe for the second quarter of 2004 compared to $6.77 per boe for the second quarter of 2003. For the second quarter of 2004, operating expenses were $9.97 per barrel of light oil, $7.28 per barrel of heavy oil and $0.82 per mcf of natural gas. The operating expenses for the same period a year ago were $8.91, $7.65 and $0.71, respectively.

Operating expenses for the first half of 2004 increased five percent to $42.7 million from $40.7 million for the first half of 2003. Operating expenses were $6.78 per boe for the first six months of 2004 compared to $6.33 per boe for the corresponding period of the prior year. For the first half of 2004, operating expenses were $9.14 per barrel of light oil, $7.39 per barrel of heavy oil and $0.79 per mcf of natural gas versus $6.32, $7.44 and $0.68, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for the second quarter of 2004 were $4.7 million compared to $4.3 million for the second quarter of 2003. These expenses were $1.48 per boe for the second quarter of 2004 compared to $1.40 for the same period in 2003. Transportation expenses were $1.62 per barrel of oil and $0.19 per mcf of natural gas. The corresponding amounts for 2003 were $1.56 and $0.16, respectively.

Transportation expenses for the six months ended June 30, 2004 were $9.6 million compared to $8.5 million for the first six months of 2003. These expenses were $1.52 per boe in 2004 compared to $1.32 in 2003. Transportation expenses were $1.68 per barrel of oil and $0.19 per mcf of natural gas in the 2004 period, and $1.50 per barrel of oil and $0.15 per mcf of natural gas in the 2003 period.

General and Administrative Expenses

General and administrative expenses for the second quarter of 2004 were $3.9 million compared to $1.8 million in 2003. On a per-sales-unit basis, these expenses were $1.22 per boe for the second quarter of 2004 compared to $0.57 per boe for 2003. In accordance with our full-cost accounting policy, $1.8 million of expenses were capitalized in the second quarter of 2003 compared to no capitalized expenses for the second quarter of 2004. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

General and administrative expenses for the first half of 2004 were $7.2 million, compared to $3.4 million for the prior year. On a per-sales-unit basis, these expenses were $1.14 per boe in 2004 and $0.52 per boe in 2003. In accordance with our full-cost accounting policy, $3.4 million of expenses were capitalized in the first six months of 2003, while no expenses have been capitalized in 2004.

Unit-based Compensation Expense

Compensation expense was $1.7 million for the second quarter of 2004 compared to $0.2 million for the second quarter of 2003.

For the six months ended June 30, 2004, compensation expense was $3.0 million compared to $0.5 million for the same period in 2003. The 2004 compensation expense was based on the amount that the market price of the trust unit exceeds the exercise price for trust unit rights issued as at the date of the consolidated financial statements. The compensation expense for 2003 was based on the fair value of the stock options outstanding prior to the Plan of Arrangement.

Interest Expenses

Interest expenses on long-term debt decreased to $5.2 million for the second quarter of 2004 from $5.3 million for the same quarter last year.

For the first six months of 2004, interest expenses on long-term debt was $9.0 million compared to $11.8 million for the same period last year. The decrease is due to the redemption of the Company's senior secured notes in May 2003 and the stronger Canadian currency as interest on the long-term notes is payable in U.S. dollars.

Foreign Exchange

The foreign exchange loss in the second quarter of 2004 was $5.4 million compared to a gain of $17.4 million in the prior year. The 2004 loss is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7460 at June 30, 2004 compared to 0.7631 at March 31, 2004. The 2003 gain is based on translation at 0.7378 at June 30, 2003 compared to 0.6806 at March 31, 2003.

The foreign exchange loss for the first six months of 2004 was $8.6 million compared to a gain of $40.2 million in the prior year. The 2004 loss is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7460 at June 30, 2004 compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation at 0.7378 at June 30, 2003 compared to 0.6331 at December 31, 2002.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion increased to $38.6 million for the second quarter of 2004 compared to $25.1 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $12.24 per boe compared to $8.09 per boe for the same quarter in 2003 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument ("NI") 51-101.

Depletion, depreciation and accretion increased to $78.6 million for the first half of 2004 compared to $51.8 million for the same period last year. On a sales-unit basis, the provision for the current period was $12.49 per boe compared to $8.04 per boe for the same period a year earlier.

Income Taxes

Current tax expenses were $2.6 million for the second quarter of 2004 compared to $1.9 million for the same quarter a year ago. The current tax expense is comprised of $1.8 million of Saskatchewan Capital Tax and $0.8 million of Large Corporation Tax compared to $1.5 million and $0.4 million, respectively, in the corresponding period in 2003.

Current tax expenses were $4.8 million for the first half of 2004 compared to $4.5 million for the same period last year. The current tax expense is comprised of $3.2 million of Saskatchewan Capital Tax and $1.6 million of Large Corporation Tax compared to $3.7 million and $0.8 million, respectively, in 2003. Overall current tax expense has increased primarily due to increased Large Corporation Tax brought about by the new capital structure present under the Trust.

Net Income (Loss)

Net loss for the second quarter of 2004 of $11.2 million was the result of increased charges for depletion, depreciation and accretion, and the losses on financial derivatives and foreign currency translation. Net income for the second quarter of 2003 was impacted by the foreign exchange gain for the period.

Net loss for the first six months of 2004 was $15.5 million and was impacted by the same factors noted in the second quarter comparison.

Liquidity and Capital Resources

At June 30, 2004, total net debt (including working capital) was $280.0 million compared to $223.1 million at June 30, 2003 and $213.6 million at December 31, 2003. The $280.0 million net debt included $31.9 million of notional liabilities based on the mark-to-market valuations of derivative contracts. At the end of June 2004, there were no amounts outstanding under the Company's bank credit facilities, which totalled $165.0 million.

Capital Expenditures

Exploration and development expenditures decreased to $45.2 million for the first half of 2004 compared to $114.7 million for the same period last year. The Trust's total capital expenditures for these periods are summarized below.

Capital Expenditures

	Six Months Ended June 30	
($ thousands)	**2004**	2003
Land	**4,108**	10,285
Seismic	**517**	4,695
Drilling and completion	**26,767**	70,502
Equipment	**12,324**	24,333
Other	**1,502**	4,871
Total exploration and development	**45,218**	114,686
Property acquisitions	**–**	5,599
Property dispositions	**–**	(137,310)
Net capital expenditures	**45,218**	(17,025)

(thousands) (unaudited)	June 30, 2004	December 31, 2003 *(restated – see note 3)*
Assets		
Current assets		
Cash and short-term investments	$ 16,008	$ 53,731
Accounts receivable	42,116	48,608
Financial derivative contracts *(note 9)*	437	–
Crude oil inventory	6,121	5,900
	64,682	108,239
Deferred derivative loss *(note 9)*	5,055	–
Deferred charges and other assets	7,131	7,764
Petroleum and natural gas properties	832,903	862,350
	$ 909,771	$ 978,353
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 62,142	$ 80,126
Distributions payable to unitholders	9,418	9,123
Financial derivative contracts *(note 9)*	31,940	–
	103,500	89,249
Long-term debt *(note 4)*	241,199	232,562
Asset retirement obligations *(note 5)*	59,080	55,996
Future income taxes	143,201	169,336
	546,980	547,143
Unitholders' Equity		
Unitholders' capital *(note 7)*	459,492	446,594
Exchangeable shares *(note 7)*	13,474	26,372
Contributed surplus	3,212	224
Accumulated distributions	(89,323)	(33,382)
Accumulated deficit	(24,064)	(8,598)
	362,791	431,210
	$ 909,771	$ 978,353

See accompanying notes to the consolidated financial statements.

	Three Months Ended June 30		Six Months Ended June 30	
(thousands, except per unit data) (unaudited)	**2004**	2003	**2004**	2003
		(restated – note 3)		*(restated – note 3)*
Revenue				
Petroleum and natural gas sales	**$ 104,517**	$ 89,999	**$ 200,663**	$ 214,804
Royalties	**(16,237)**	(16,183)	**(31,528)**	(38,424)
Realized loss on financial derivatives	**(16,416)**	(6,379)	**(25,838)**	(19,960)
Unrealized loss on financial derivatives	**(7,109)**	–	**(21,393)**	–
	64,755	67,437	**121,904**	156,420
Expenses				
Operating	**21,384**	21,003	**42,659**	40,735
Transportation *(note 3)*	**4,684**	4,332	**9,594**	8,509
General and administrative	**3,853**	1,764	**7,169**	3,364
Unit-based compensation *(note 8)*	**1,707**	198	**2,988**	515
Interest *(note 4)*	**5,161**	5,330	**9,033**	11,787
Costs on redemption of notes *(note 4)*	**–**	4,768	**–**	4,768
Foreign exchange loss (gain)	**5,380**	(17,363)	**8,637**	(40,195)
Depletion, depreciation and accretion	**38,610**	25,099	**78,634**	51,802
	80,779	45,131	**158,714**	81,285
Income (loss) before income taxes	**(16,024)**	22,306	**(36,810)**	75,135
Income taxes				
Current expense	**2,629**	1,886	**4,791**	4,456
Future expense (recovery) *(note 6)*	**(7,483)**	(19,909)	**(26,135)**	(1,754)
	(4,854)	(18,023)	**(21,344)**	2,702
Net income (loss)	**$ (11,170)**	$ 40,329	**(15,466)**	72,433
Accumulated deficit, beginning of period, as previously reported			**(351)**	(38,489)
Accounting policy change for asset retirement obligations *(note 3)*			**(8,247)**	(5,424)
Accumulated deficit, beginning of period, as restated			**(8,598)**	(43,913)
Accumulated earnings (deficit), end of period			**$ (24,064)**	$ 28,520
Net income (loss) per trust unit				
Basic	**$ (0.17)**	$ 0.75	**$ (0.24)**	$ 1.36
Diluted	**$ (0.17)**	$ 0.73	**$ (0.24)**	$ 1.32

See accompanying notes to the consolidated financial statements.

	Three Months Ended June 30		Six Months Ended June 30	
(thousands) (unaudited)	**2004**	2003	**2004**	2003
		(restated – note 3)		*(restated – note 3)*
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**$ (11,170)**	$ 40,329	**$ (15,466)**	$ 72,433
Items not affecting cash:				
Unit-based compensation *(note 7)*	**1,707**	198	**2,988**	515
Amortization of deferred charges	**2,791**	250	**5,582**	510
Costs on redemption of notes *(note 4)*	**–**	4,768	**–**	4,768
Foreign exchange loss (gain)	**5,380**	(17,363)	**8,637**	(40,195)
Depletion, depreciation and accretion	**38,610**	25,099	**78,634**	51,802
Unrealized loss on financial derivatives *(note 9)*	**7,109**	–	**21,393**	–
Future income taxes recovery	**(7,483)**	(19,909)	**(26,135)**	(1,754)
Cash flow from operations	**36,944**	33,372	**75,633**	88,079
Change in non-cash working capital	**4,015**	9,040	**(126)**	(13,882)
Site restoration and reclamation expenditures	**(207)**	(85)	**(885)**	(467)
Decrease (increase) in deferred charges and other assets	**53**	(528)	**106**	(476)
	40,805	41,799	**74,728**	73,254
Financing Activities				
Redemption of senior secured notes *(note 4)*	**–**	(89,950)	**–**	(89,950)
Increase in deferred charges and other assets	**–**	(1,012)	**–**	(2,137)
Payments of distributions	**(28,224)**	–	**(55,646)**	–
Issue of common shares	**–**	1,228	**–**	3,896
	(28,224)	(89,734)	**(55,646)**	(88,191)
Investing Activities				
Petroleum and natural gas property expenditures	**(15,975)**	(59,019)	**(45,218)**	(120,285)
Disposal of petroleum and natural gas properties	**–**	2,306	**–**	137,310
Change in non-cash working capital	**(13,129)**	(18,363)	**(11,587)**	13,250
	(29,104)	(75,076)	**(56,805)**	30,275
Change in cash and short-term investments	**(16,523)**	(123,011)	**(37,723)**	15,338
Cash and short-term investments, beginning of period	**32,531**	142,447	**53,731**	4,098
Cash and short-term investments, end of period	**$ 16,008**	$ 19,436	**$ 16,008**	$ 19,436

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, 2003, except as described in note 3. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes thereto for the year ended December 31, 2003.

3. CHANGES IN ACCOUNTING POLICIES

Unit-Based Compensation

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Previously reported amounts for 2003 have been restated to give effect to the standard as at January 1, 2003. Compensation expense of $0.52 million was recorded for the six months ended June 30, 2003 (three months ended June 30, 2003 – $0.20 million) for all stock options granted by the Company since January 1, 2003, with a corresponding amount recorded as contributed surplus (see note 8).

Full-Cost Accounting

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

Asset Retirement Obligations

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

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative six months ended June 30, 2003 decreased by $1.8 million, net of future income tax of $0.02 million (three months ended June 30, 2003 – $1.3 million, net of future income tax of $0.37 million). At December 31, 2003 the asset retirement obligations balance increased by $32.5 million to $55.9 million, the petroleum and natural gas assets balance increased by $19.7 million to $862.3 million and the future tax liability decreased by $5.0 million to $169.3 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow as a result of adopting this policy (see note 5).

Financial Derivative Contracts

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

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

As of January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance is being recognized in income over the term of the previously designated hedged item. At June 30, 2004, the Trust recorded a liability of $31.9 million and an asset of $0.44 million on the mark-to-market value of the non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from January 1, 2004 to June 30, 2004 has been recorded as an unrealized loss on non-hedging financial derivatives of $21.4 million in the consolidated statement of operations (see note 9).

Three Months and Six Months Ended June 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles," is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the six months ended June 30, 2004 both increased by $9.6 million (2003 – $8.5 million) and for the three months ended June 30, 2004 increased by $4.7 million (2003 – $4.3 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

4. LONG-TERM DEBT

	June 30, 2004	December 31, 2003
10.5% senior subordinated notes (US$247)	$ 331	$ 319
9.625% senior subordinated notes (US$179,699)	240,868	232,243
	$ 241,199	$ 232,562

Interest Expense

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

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	2004	2003
Credit facility charges	$ 117	$ (31)	$ 257	$ –
Amortization of deferred charge	264	250	527	510
Long-term debt	4,780	5,111	8,249	11,277
Total interest	$ 5,161	$ 5,330	$ 9,033	$ 11,787

5. ASSET RETIREMENT OBLIGATIONS

	June 30, 2004	December 31, 2003
Balance, beginning of period	$ 55,996	$ 52,244
Liabilities incurred	1,729	4,010
Liabilities settled	(885)	(880)
Disposition of liabilities	–	(3,335)
Accretion	2,240	3,957
Balance, end of period	$ 59,080	$ 55,996

Three Months and Six Months Ended June 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

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, 2004 is $120.8 million (December 31, 2003 – $117.0 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.

6. INCOME TAXES

Future income tax expense for the period ended June 30, 2004 included a non-recurring adjustment to future income taxes resulting from a decrease in the Alberta corporate income tax rate from 12.5 percent to 11.5 percent.

7. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Trust Units

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

Trust Units	# of units	Amount
Balance December 31, 2003	60,821	$ 446,594
Issued on conversion of exchangeable shares	1,962	12,898
Balance June 30, 2004	62,783	$ 459,492

Exchangeable Shares

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, 2004 was 1.13235 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Exchangeable Shares	# of shares	Amount
Balance December 31, 2003	3,725	$ 26,372
Exchanged for trust units	(1,822)	(12,898)
Balance June 30, 2004	1,903	$ 13,474

Three Months and Six Months Ended June 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

8. TRUST UNIT RIGHTS

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

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

Compensation expense is 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 earning over the vesting period of the Plan. Compensation expense for the unit rights for the six months ended June 30, 2004 was $3.0 million (three months ended June 30, 2004 – $1.7 million).

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

	# of rights	Weighted average exercise price (1)
Balance December 31, 2003	2,855	$ 9.34
Granted	228	$ 10.98
Cancelled	(444)	$ 9.60
Balance June 30, 2004	2,639	$ 9.28

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

The adoption of the amendments related to accounting for unit-based compensation (note 3) also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. For the six months ended June 30, 2003, compensation expense related to the stock options granted by the Company since January 1, 2003 was $0.32 million (three months ended June 30, 2003 – $0.20 million). Compensation expense for options granted during 2003 was based on the estimated fair value at the time of the grant and the expense was recognized over the vesting period of the options.

9. FINANCIAL DERIVATIVE CONTRACTS

At June 30, 2004, the Trust had financial derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2004	5,000 bbls/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbls/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbls/d	US$24.00 – $32.05	WTI

Three Months and Six Months Ended June 30, 2004 and 2003 (all tabular amounts in thousands, except per unit amounts)

			Exchange Rate	
Foreign currency	Period	Amount	Floor	Cap
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3100	CAD/USD $1.3400
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3280	CAD/USD $1.3560
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3160	CAD/USD $1.3365
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3400	CAD/USD $1.3665

Interest rate swap	Period	Principal	Rate
	November 2003 to July 2010	US$179,669,000	3-month LIBOR plus 5.2%

As discussed in note 3, at January 1, 2004, the fair value of all outstanding financial derivative contracts that are not considered accounting hedges was recorded on the consolidated balance sheet with an offsetting deferred credit. The deferred credit is recognized into income over the life of the associated contracts. Under the new guideline for hedge accounting, the Trust's financial derivative contracts for oil and foreign currency do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair-value method. The changes in the fair value of these hedges are as follows:

January 1, 2004 mark-to-market value	$ 10,110
Change in fair value	21,393
June 30, 2004 mark-to-market value	$ 31,503

10. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Interest paid	**$ 55**	$ 1,435	**$ 10,553**	$ 15,374
Income taxes paid	**$ 8,201**	$ 2,081	**$ 13,052**	$ 8,768

11. RECLASSIFICATION

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

12. SUBSEQUENT EVENTS

In July 2004, the Trust entered into crude oil derivative contracts for the year 2005 for an aggregate of 8,000 barrels per day with average prices collared between WTI US$35.00 and US$42.55 per barrel.

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

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

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

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AUDITORS

Deloitte & Touche LLP

BANKERS

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

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
mmboe	million 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 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.