HIGHLIGHTS

Baytex Energy Trust (TSX: BTE.UN; NYSE: BTE) is pleased to announce its operating and financial results for the three months and six months ended June 30, 2006.

Highlights of the second quarter in 2006 include:

- Achieved cash flow of $69.5 million, 39% higher than Q2/05 and equivalent to Q1/06;
- Increased net income to $56.2 million, 235% higher than Q2/05 and 94% higher than Q1/06;
- Maintained a conservative and sustainable payout ratio of 53% for the second quarter and the first half of 2006;
- Improved financial flexibility with total net debt reducing to $384 million at June 30, 2006 from $418 million at December 31, 2005 and $472 million one year ago; and
- Generated a total return of 23% to unitholders in the second quarter and 44% in the first half of 2006.

Financial	**Three Months Ended**			**Six Months Ended**	
($ thousands, except per unit amounts)	**June 30, 2006**	March 31, 2006	June 30, 2005	**June 30, 2006**	June 30, 2005
			(restated - note 3)		*(restated - note 3)*
Petroleum and natural gas sales	**140,163**	136,231	118,379	**276,394**	229,654
Cash flow from operations[1]	**69,465**	69,748	49,937	**139,213**	94,477
Per unit - basic	**0.96**	0.99	0.75	**1.94**	1.42
- diluted	**0.88**	0.90	0.71	**1.79**	1.35
Cash distributions	**36,569**	36,768	28,823	**73,337**	58,144
Per unit	**0.54**	0.54	0.45	**1.08**	0.90
Net income	**56,162**	28,879	16,779	**85,041**	5,168
Per unit - basic	**0.77**	0.41	0.25	**1.19**	0.08
- diluted	**0.73**	0.39	0.25	**1.13**	0.08
Exploration and development	**27,468**	44,886	31,586	**72,354**	60,051
Net acquisitions (dispositions)	**(38)**	(570)	847	**(608)**	756
Total capital expenditures	**27,430**	44,316	32,433	**71,746**	60,807
Long-term notes	**200,640**	210,015	220,542	**200,640**	220,542
Convertible debentures	**29,564**	42,989	95,255	**29,564**	95,255
Bank loan	**140,187**	124,107	109,267	**140,187**	109,267
Other working capital deficiency	**4,736**	25,139	16,916	**4,736**	16,916
Notional marked-to-market liabilities	**8,961**	1,435	30,761	**8,961**	30,761
Total net debt	**384,088**	403,685	472,741	**384,088**	472,741
Operating					
Daily production					
Light oil & NGL (bbl/d)	**3,619**	4,089	3,404	**3,853**	3,639
Heavy oil (bbl/d)	**20,413**	21,134	19,653	**20,771**	20,462
Total oil (bbl/d)	**24,032**	25,223	23,058	**24,624**	24,100
Natural gas (MMcf/d)	**54.7**	60.6	59.3	**57.6**	59.4
Oil equivalent (boe/d @ 6:1)	**33,154**	35,319	32,937	**34,231**	33,996
Average prices (before hedging)					
WTI oil (US$/bbl)	**70.70**	63.48	53.17	**67.09**	51.51
Edmonton par oil ($/bbl)	**78.61**	68.99	65.76	**73.80**	63.60
BTE light oil & NGL ($/bbl)	**57.83**	51.33	53.06	**54.40**	49.68
BTE heavy oil ($/bbl)	**47.10**	37.87	35.71	**42.45**	33.18
BTE total oil ($/bbl)	**48.71**	40.05	38.27	**44.32**	35.67
BTE natural gas ($/Mcf)	**6.68**	8.36	7.08	**7.56**	6.88
BTE oil equivalent ($/boe)	**46.35**	42.94	39.53	**44.60**	37.31

	Three Months Ended			Six Months Ended	
	June 30, 2006	March 31, 2006	June 30, 2005	**June 30, 2006**	June 30, 2005
Trust Unit Information					
TSX (C$)					
Unit Price					
High	**$25.39**	$20.90	$15.20	**$25.39**	$15.70
Low	**$19.72**	$16.81	$12.71	**$16.81**	$12.42
Close	**$24.20**	$20.21	$13.48	**$24.20**	$13.48
Volume traded (thousands)	**22,379**	24,430	17,403	**46,808**	43,813
NYSE (US$)(2)					
Unit Price					
High	**$22.97**	$17.90	N/A	**$22.97**	N/A
Low	**$17.08**	$16.99	N/A	**$16.99**	N/A
Close	**$21.70**	$17.37	N/A	**$21.70**	N/A
Volume traded (thousands)	**6,827**	736	N/A	**7,563**	N/A
Units outstanding (thousands)(3)	**75,448**	74,217	69,264	**75,448**	69,264
Foreign ownership	**38%**	34%	32%	**38%**	32%

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

(2) Data reflects the periods since commencement of trade on March 27, 2006 on the NYSE.

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

MESSAGE TO UNITHOLDERS

Operations Review

Production for the second quarter in 2006 averaged 33,154 boe/d compared to 35,319 boe/d in the first quarter of 2006 and 32,937 boe/d for the same period last year. The second quarter production was lower than that in the first quarter of 2006 primarily due to the effects of spring break-up on oilfield transportation and curtailment of gas production through third party controlled facilities. Production is expected to increase during the second half of the year and Baytex is maintaining its 2006 average production target of 35,000 boe/d.

Capital expenditures for the quarter totaled $27.4 million. During this period, Baytex participated in the drilling of 17 (17.0 net) wells, resulting in 15 (15.0 net) oil wells and two (2.0 net) gas wells. Overall drilling success rate was 100% (100.0% net).

Heavy oil production averaged 20,413 bbl/d during the second quarter of 2006 compared to 21,134 bbl/d in the first quarter of 2006 and 19,653 bbl/d in the second quarter of 2005. At Celtic, Baytex continued to realize on the exploitation upside of these assets acquired last year. Average production in this area increased to approximately 4,000 boe/d in the second quarter, more than doubling the production level when the property was purchased in September 2005. Six oil wells were drilled in this area during the second quarter, with another 15 wells planned for the remainder of the year together with numerous recompletions operations.

At Seal, the two horizontal wells drilled last winter were put on production at initial rates of approximately 150 bbl/d per well during the second quarter. Baytex has advanced its marketing plans for Seal by successfully hauling crude into heavy oil markets in southeast Alberta. Based on the success of this test of long-haul trucking, Baytex has the potential to cost-effectively expand the operations of its AIM Transport subsidiary to handle increasing production from Seal. Expansion of AIM Transport into this market would not only provide transportation service at reasonable cost, but would also provide the flexibility to access either medium sour or heavy blend crude markets, depending on which market provides the highest realized price. At the same time, Baytex continues to investigate third party transportation arrangements through pipelines to market crude from Seal. Baytex is confident that marketing issues will be resolved in time to commence large scale development of Seal during 2007.

Natural gas production averaged 54.7 MMcf/d in the second quarter of 2006 compared to 60.6 MMcf/d in the first quarter of 2006 and 59.3 MMcf/d in the second quarter of 2005. Approximately 1.9 MMcf/d of the quarter-over-quarter production difference was attributable to an accounting adjustment relating to the properties acquired in Celtic last year. Natural gas production was also hampered in certain winter-access areas by unanticipated restrictions at third-party gas processing facilities, which will result in the delay of production from four wells drilled in the first quarter this year until next winter. Baytex plans to replace a portion of this curtailed production with other gas and light oil projects in its portfolio during the second half of 2006.

At Stoddart, one successful gas well was drilled in the second quarter and is currently being tied in for production. Natural gas and NGLs production in the second quarter in this area averaged 3,900 boe/d compared to 3,200 boe/d in the same period last year. Four new wells are planned for the second half of 2006, along with a number of recompletion projects.

Baytex was successful at holding operating costs to $8.51 per boe in the second quarter compared to $8.74 per boe in the first quarter of 2006. Transportation expenses for oil, however, were higher in the second quarter at $2.51 per barrel compared to $2.21 per barrel in the previous quarter as trucking costs were affected by higher fuel charges and reduced load allowables due to spring-break road conditions.

Financial Review

Cash flow from operations of $69.5 million in the second quarter was comparable to the $69.7 million for the prior quarter. The impact of declining natural gas prices and a temporary reduction in production was substantially offset by higher oil prices. Sales revenue was bolstered by the narrowing in heavy oil differentials (WTI to Lloyd Blend spread) from 46% in the first quarter to 26% in the second quarter. The full benefit of the improvement in heavy oil prices was muted to Baytex as a result of the long term supply agreement with Frontier Oil Corporation, which fixes the price differential at 29%. Nonetheless, the substantial improvement in heavy oil pricing fundamentals due to industry investments in pipeline infrastructure and heavy oil refining capacity should bode well for Baytex's long-term cash generation capability.

Cash flow for the second quarter was affected by an increase in the effective royalty rate on heavy oil revenue. Crown royalties are based on market prices realized by the industry in the period. As the market price for heavy oil in the second quarter was higher than the average price received by Baytex due to the Frontier contract, Baytex's effective royalty rate for heavy oil in the second quarter was 17.4% compared to 10.8% for the same period last year.

Natural gas prices continued to decline in the second quarter, with Baytex receiving an average $6.68 per Mcf during this period compared to $8.36 per Mcf in the first quarter of 2006. Volatility in gas prices has been unabated thus far this summer. Accordingly, Baytex continues to employ a prudent hedging strategy in order to protect cash flow for the coming quarters.

Net income for the quarter was positively impacted by a future income tax recovery of $24.7 million, primarily resulting from reductions to future federal income tax rates. Current tax expense was also reduced by $0.4 million as a result of the enactment of legislation eliminating the Large Corporation Tax.

Baytex continues to report one of the lowest payout ratios in the oil and gas income trust sector at 53% for both the second quarter and the first half of 2006. With expected increases in cash flow during the second half of 2006 resulting from stronger commodity prices and higher production, the payout ratio in the second half could be further improved.

Increase in Capital Budget

The Board of Directors of Baytex has approved an increase in the 2006 capital budget to $128 million from the $105 million approved in November of last year. Approximately $10 million of this increase is due to industry-wide inflation beyond levels anticipated in the original budget. The remaining additional expenditures are designed to capture an increasing array of opportunities identified thus far in 2006. These opportunities include the establishment of new exploration ventures, infrastructure investments for the future development in the Seal area, and additional exploitation activities in both the Heavy Oil and Conventional Business Units. With this increased level of capital spending, Baytex is targeting to exit 2006 with a production rate in excess of 35,000 boe/d.

Total net debt at June 30, 2006 amounted to $384 million, a decrease of $20 million from that at the end of the last quarter, and a decrease of $89 million from one year ago. Based on current outlook of commodity prices and production, Baytex expects to generate an operating cash surplus after distributions and capital expenditures during the second half of 2006. With a growing production base and an improving financial picture, Baytex is positioned to deliver even stronger results for the remainder of this year.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
August 9, 2006

Management's discussion and analysis ("MD&A"), dated August 9, 2006, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and six months ended June 30, 2006 and the audited consolidated financial statements and MD&A for the year ended December 31, 2005. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

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

Production

Light oil and NGL production for the second quarter of 2006 increased by 6% to 3,619 bbl/d from 3,404 bbl/d a year earlier. Heavy oil production also increased by 4% to 20,413 bbl/d for the second quarter of 2006 compared to 19,653 bbl/d a year ago. Natural gas production decreased by 8% to 54.7 MMcf/d for the second quarter of 2006 compared to 59.3 MMcf/d for the same period last year. The decrease in natural gas was primarily due to unanticipated restrictions at third-party gas processing facilities and a prior period adjustment relating to assets acquired last year.

For the first half of 2006, light oil & NGL production increased by 6% to 3,853 bbl/d from 3,639 bbl/d for the same period last year. Heavy oil production for the first six months in 2006 increased to 20,771 bbl/d compared to 20,462 bbl/d for the same period in 2005. Natural gas production decreased by 3% to average 57.6 MMcf/d for the first six months in 2006 compared to 59.4 MMcf/d for 2005.

Revenue

Petroleum and natural gas sales increased 18% to $140.2 million for the second quarter of 2006 from $118.4 million for the same period in 2005. For the per sales unit calculations, heavy oil sales for the three months ended June 30, 2006 were 80 bbl/d higher (three months ended June 30, 2005 - 31 bbl/d lower) 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, 2006 was an increase of six barrels per day (six months ended June 30, 2005 – an increase of 10 barrels per day).

Revenue from light oil and NGL for the second quarter of 2006 increased 16% from the same period a year ago due to a 6% increase in production and a 9% increase in wellhead prices. Revenue from heavy oil increased 38% due to a 4% increase in production in addition to a 32% increase in wellhead prices. Revenue from natural gas decreased 13% as a result of an 8% decrease in production combined with a 6% decrease in wellhead prices.

Three Months Ended June 30

	2006		2005	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**19,047**	**57.83**	16,438	53.06
Heavy oil	**87,835**	**47.10**	63,756	35.71
Derivative contracts gain (loss)	**903**	**0.48**	(9,797)	(5.49)
Total oil revenue	**107,785**	**49.12**	70,397	33.60
Natural gas revenue (Mcf)	**33,281**	**6.68**	38,185	7.08
Total revenue (boe @ 6:1)	**141,066**	**46.64**	108,582	36.26

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

	Six Months Ended June 30			
	2006		2005	
	$000s	**$/Unit(1)**	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**37,937**	**54.40**	32,724	49.69
Heavy oil	**159,627**	**42.45**	122,949	33.18
Derivative contracts gain (loss)	**1,046**	**0.28**	(16,439)	(4.44)
Total oil revenue	**198,610**	**44.55**	139,234	37.58
Natural gas revenue (Mcf)	**78,830**	**7.56**	73,981	6.88
Total revenue (boe @ 6:1)	**277,440**	**44.77**	213,215	34.64

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

For the first six months of 2006, light oil revenue increased 16% from the same period last year due to a 9% increase in wellhead prices and a 6% increase in production. Revenue from heavy oil increased 30% mainly due to a 28% increase in wellhead prices. Revenue from natural gas increased 7% compared to the first six months of 2005 due to a 10% increase in wellhead prices and a 3% decrease in production.

Royalties

Total royalties increased to $24.0 million for the second quarter of 2006 from $15.4 million in 2005. This increase is reflective of the increase in total revenue. Total royalties for the second quarter of 2006 were 17.1% of sales compared to 13.0% of sales for the same period in 2005. For the second quarter of 2006, royalties were 15.1% of sales for light oil and NGL, 17.4% for heavy oil and 17.6% for natural gas. These rates compared to 16.0%, 10.8% and 15.4%, respectively, for the same period last year. Royalties are generally based on market prices realized by the industry in the period. As the market price for heavy oil in the second quarter was higher than the average price received by Baytex due to the Frontier contract, Baytex's effective royalty rate for heavy oil in the second quarter was a historical high of 17.4%.

For the six months ended June 30, 2006, royalties increased to $42.1 million from $32.0 million for the same period last year. Total royalties for the first six months of 2006 were 15.2% of sales, compared to 13.9% of sales for the corresponding period a year ago. For the first six months of 2006, royalties were 14.8% of sales for light oil and NGL, 13.8% for heavy oil and 18.4% for natural gas. These rates compared to 14.9%, 11.1% and 18.3%, respectively, for the same period in 2005.

Gain (Loss) on Financial Derivatives

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil and foreign currency do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method where outstanding contracts are marked-to-market at each month end, and the change in value recorded as unrealized gain or loss. As the contracts come to the end of their terms, the gain or loss is realized.

Derivative contracts yielded a realized gain of $0.9 million in the second quarter of 2006 compared to a realized loss of $9.8 million for the same period in the prior year. Derivative contracts outstanding at June 30, 2006 were marked-to-market with an unrealized loss of $7.5 million.

Operating Expenses

Operating expenses for the second quarter of 2006 increased to $25.7 million from $24.2 million in the corresponding quarter last year. Operating expenses were $8.51 per boe for the second quarter of 2006 compared to $8.07 per boe for the second quarter of 2005. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services. For the second quarter of 2006, operating expenses were $11.79 per barrel of light oil and NGL, $8.63 per barrel of heavy oil and $1.16 per Mcf of natural gas. The operating expenses for the same period a year ago were $9.12, $8.88 and $1.02, respectively.

Operating expenses for the first six months of 2006 increased to $53.5 million from $49.8 million for the first six months in 2005. Operating expenses were $8.63 per boe for the first six months of 2006 compared to $8.09 per boe for the corresponding period of the prior year. For the first half of 2006, operating expenses were $10.05 per barrel of light oil and NGL, $9.08 per barrel of heavy oil and $1.18 per Mcf of natural gas versus $9.87, $8.73 and $1.02, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for the second quarter of 2006 were $6.2 million compared to $5.6 million for the second quarter of 2005. These expenses were $2.04 per boe for the second quarter of 2006 compared to $1.89 for the same period in 2005. Transportation expenses were $2.51 per barrel of oil and $0.13 per Mcf of natural gas. The corresponding amounts for 2005 were $2.34 and $0.14, respectively.

Transportation expenses for the six months ended June 30, 2006 were $11.9 million compared to $11.1 million for the first six months of 2005. These expenses were $1.91 per boe in 2006 compared to $1.81 in 2005. Transportation expenses were $2.36 per barrel of oil and $0.13 per Mcf of natural gas in the 2006 period, and $2.20 per barrel of oil and $0.14 per Mcf of natural gas in the 2005 period.

General and Administrative Expenses

General and administrative expenses for the second quarter of 2006 increased to $5.4 million from $3.9 million in 2005. On a per sales unit basis, these expenses were $1.77 per boe for the second quarter of 2006 compared to $1.30 per boe for the same period in 2005. The increased costs are due to escalating costs in the labour market, increased office rent expenses, additional expenses associated with the New York Stock Exchange listing, and costs relating to compliance requirements under the Sarbanes-Oxley Act. In accordance with our full cost accounting policy, no expenses were capitalized in either the second quarter of 2006 or 2005.

General and administrative expenses for the first six months of 2006 were $10.1 million, compared to $7.5 million for the prior year. On a per sales unit basis, these expenses were $1.63 per boe in 2006 and $1.22 per boe in 2005. The increase is attributable to the same factors influencing the second quarter variance. In accordance with our full cost accounting policy, no expenses were capitalized in either 2006 or 2005.

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the second quarter of 2006 compared to $1.0 million for the second quarter of 2005. For the six months ended June 30, 2006, compensation expense was $3.6 million compared to $2.3 million for the same period in 2005.

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

Interest Expenses

Interest expense increased to $8.7 million for the second quarter of 2006 from $7.8 million for the same quarter last year, primarily due to the general increase in interest rates and the issuance of the 6.5% convertible debentures in June 2005.

For the first six months of 2006, interest expense was $17.4 million compared to $14.9 million for the same period last year. The increase is attributable to the same factors influencing the second quarter variance.

Foreign Exchange

Foreign exchange in the second quarter of 2006 was a gain of $9.4 million compared to a loss of $2.9 million in the prior year. The gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8969 at June 30, 2006 compared to 0.8568 at March 31, 2006. The 2005 loss is based on translation at 0.8159 at June 30, 2005 compared to 0.8267 at March 31, 2005.

Foreign exchange for the first six months of 2006 was a gain of $9.2 million compared to a loss of $4.0 million in the prior year. The 2006 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8968 at June 30, 2006 compared to 0.8577 at December 31, 2005. The 2005 loss is based on translation at 0.8159 at June 30, 2005 compared to 0.8308 at December 31, 2004.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion for the second quarter of 2006 has decreased to $36.6 million from $41.5 million for the same quarter a year ago despite higher production. This decrease is due to a lower depletion rate resulting from low-cost proved reserves added from the Celtic acquisition and development activities during 2005. On a sales-unit basis, the provision for the current quarter was $12.12 per boe compared to $13.86 per boe for the same quarter in 2005.

Depletion, depreciation and accretion decreased to $74.8 million for the first half of 2006 compared to $84.8 million for the same period last year. On a sales-unit basis, the provision for the current period was $12.07 per boe compared to $13.77 per boe for the same period a year earlier.

Income Taxes

Current tax expenses decreased to $1.9 million for the second quarter of 2006 from $2.0 million for the same quarter a year ago. The current tax expense is comprised of $2.3 million of Saskatchewan Capital Tax and a recovery of $0.4 million of Large Corporation Tax, reflecting the elimination of the Large Corporation Tax. This is compared to $1.5 million Saskatchewan Capital Tax and $0.5 million Large Corporation Tax in the corresponding period in 2005.

Current tax expenses were $4.1 million for the first half of 2006 compared to $4.0 million for the same period last year. The current tax expense is comprised of $4.0 million of Saskatchewan Capital Tax and $0.1 million of Large Corporation Tax compared to $3.1 million and $0.9 million, respectively, in 2005.

Net Income

Net income for the second quarter of 2006 was $56.2 million compared to $16.8 million for the second quarter in 2005. The variance was the result of higher production and higher sales prices, combined with a substantial foreign exchange gain, lower depletion expense and higher tax recoveries. This was partially offset by the unrealized loss on financial derivatives, higher royalty rates and higher operating costs.

Net income for the first six months of 2006 was $85.0 million compared to $5.2 million for the same period in 2005. The variance was primarily due to higher production, higher sales prices, lower loss in financial derivatives, lower depletion expense and higher tax recoveries for the 2006 period. This was partially offset by higher royalty rates and higher operating costs.

Liquidity and Capital Resources

At June 30, 2006, total net debt excluding notional marked-to-market assets or liabilities was $375.1 million compared to $423.7 million at the end of 2005. Borrowings under Baytex's bank facilities were $140.2 million, with the capacity of the facilities set at $300 million. As at June 30, 2006, $69.2 million principal amount of the 6.5% convertible debentures (original issue at $100 million) had been tendered for conversion into trust units.

Capital Expenditures

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2006**	2005	**2006**	2005
Land	**2,739**	2,802	**6,049**	4,007
Seismic	**994**	839	**1,193**	1,359
Drilling and completion	**18,213**	20,752	**50,653**	42,225
Equipment	**4,765**	6,073	**13,535**	10,359
Other	**757**	1,120	**924**	2,101
Total exploration and development	**27,468**	31,586	**72,354**	60,051
Net property acquisitions (dispositions)	**(38)**	847	**(608)**	756
Total capital expenditures	**27,430**	32,433	**71,746**	60,807

CONSOLIDATED BALANCE SHEETS

(thousands) (unaudited)		**June 30, 2006**		December 31, 2005
Assets				
Current assets				
Accounts receivable	**$**	**78,245**	$	73,869
Crude oil inventory		**10,632**		9,984
Financial derivative contracts *(note 12)*		**-**		5,183
		88,877		89,036
Deferred charges and other assets		**5,651**		9,038
Petroleum and natural gas properties		**968,689**		969,738
Goodwill		**37,755**		37,755
	$	**1,100,972**	$	1,105,567
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**80,440**	$	89,966
Distributions payable to unitholders		**13,173**		10,393
Bank loan		**140,187**		123,588
Financial derivative contracts *(note 12)*		**8,961**		-
		242,761		223,947
Long-term debt *(note 4)*		**200,640**		209,799
Convertible debentures *(note 5)*		**29,564**		73,766
Asset retirement obligations *(note 6)*		**33,074**		33,010
Deferred obligations *(note 13)*		**3,474**		4,558
Future income taxes		**128,693**		159,745
		638,206		704,825
Non-controlling interest *(note 8)*		**14,050**		12,810
Unitholders' Equity				
Unitholders' capital *(note 7)*		**609,036**		555,020
Conversion feature of debentures *(note 5)*		**1,476**		3,698
Contributed surplus		**12,084**		10,332
Accumulated distributions		**(345,789)**		(267,986)
Accumulated income		**171,909**		86,868
		448,716		387,932
	$	**1,100,972**	$	1,105,567

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME

	Three Months Ended June 30		Six Months Ended June 30	
(thousands, except per unit data) (unaudited)	**2006**	2005	**2006**	2005
		(restated - note 3)		*(restated - note 3)*
Revenue				
Petroleum and natural gas sales	**$ 140,163**	$ 118,379	**$ 276,394**	$ 229,654
Royalties	**(24,018)**	(15,434)	**(42,083)**	(32,012)
Realized gain (loss) on financial derivatives	**903**	(9,797)	**1,046**	(16,439)
Unrealized gain (loss) on financial derivatives	**(7,527)**	11,066	**(14,144)**	(21,247)
	109,521	104,214	**221,213**	159,956
Expenses				
Operating	**25,733**	24,176	**53,453**	49,814
Transportation	**6,166**	5,647	**11,860**	11,117
General and administrative	**5,356**	3,885	**10,090**	7,540
Unit based compensation *(note 3)*	**1,821**	1,048	**3,552**	2,340
Interest *(note 10)*	**8,651**	7,848	**17,437**	14,894
Foreign exchange loss (gain)	**(9,375)**	2,879	**(9,159)**	3,959
Depletion, depreciation and accretion	**36,639**	41,497	**74,806**	84,776
	74,991	86,980	**162,039**	174,440
Income (loss) before income taxes and non-controlling interest	**34,530**	17,234	**59,174**	(14,484)
Income taxes (recovery)				
Current	**1,908**	2,015	**4,067**	3,982
Future	**(24,742)**	(2,007)	**(31,334)**	(23,764)
	(22,834)	8	**(27,267)**	(19,782)
Income before non-controlling interest	**57,364**	17,226	**86,441**	5,298
Non-controlling interest *(note 8)*	**(1,202)**	(447)	**(1,400)**	(130)
Net income	**56,162**	16,779	**85,041**	5,168
Accumulated income (deficit), beginning of period, as previously reported	**115,747**	(11,117)	**86,868**	5,694
Accounting policy change for unit based compensation *(note 3)*	**-**	6,498	**-**	1,298
Accumulated income (deficit), beginning of period, as restated	**115,747**	(4,619)	**86,868**	6,992
Accumulated income, end of period	**$ 171,909**	$ 12,160	**$ 171,909**	$ 12,160
Net income per trust unit				
Basic	**$ 0.77**	$ 0.25	**$ 1.19**	$ 0.08
Diluted	**$ 0.73**	$ 0.25	**$ 1.13**	$ 0.08
Weighted average trust units				
Basic	**72,503**	66,874	**71,589**	66,745
Diluted	**79,296**	71,922	**78,255**	71,017

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
(thousands) (unaudited)	**2006**	2005	**2006**	2005
		(restated - note 3)		*(restated - note 3)*
Cash provided by (used in):				
Operating Activities				
Net income	**$ 56,162**	$ 16,779	**$ 85,041**	$ 5,168
Items not affecting cash:				
Unit based compensation *(note 3, 9)*	**1,821**	1,048	**3,552**	2,340
Amortization of deferred charges	**200**	314	**649**	574
Foreign exchange loss (gain)	**(9,375)**	2,879	**(9,159)**	3,959
Depletion, depreciation and accretion	**36,639**	41,497	**74,806**	84,776
Accretion on debentures	**31**	46	**114**	46
Unrealized loss (gain) on financial derivatives *(note 12)*	**7,527**	(11,066)	**14,144**	21,248
Future income tax recovery	**(24,742)**	(2,007)	**(31,334)**	(23,764)
Non-controlling interest *(note 8)*	**1,202**	447	**1,400**	130
	69,465	49,937	**139,213**	94,477
Change in non-cash working capital	**(15,667)**	(208)	**(14,753)**	(17,213)
Asset retirement expenditures	**(746)**	(50)	**(1,153)**	(1,022)
Decrease (increase) in deferred charges and other assets	**(489)**	228	**(978)**	(244)
	52,563	49,907	**122,329**	75,998
Financing Activities				
Issuance of convertible debentures *(note 5)*	**-**	100,000	**-**	100,000
Convertible debentures issue costs *(note 5)*	**-**	(4,250)	**-**	(4,250)
Increase (decrease) in bank loan	**16,080**	(81,003)	**16,599**	(52,177)
Payments of distributions	**(37,335)**	(29,381)	**(71,050)**	(58,779)
Issue of trust units	**1,075**	479	**3,665**	1,582
	(20,180)	(14,155)	**(50,786)**	(13,624)
Investing Activities				
Petroleum and natural gas property expenditures	**(27,433)**	(32,534)	**(72,519)**	(60,999)
Disposal of petroleum and natural gas properties	**3**	101	**773**	192
Change in non-cash working capital	**(4,953)**	(3,319)	**203**	(1,567)
	(32,383)	(35,752)	**(71,543)**	(62,374)
Change in cash and cash equivalents	**-**	**-**	**-**	**-**
Cash and cash equivalents, beginning of period	**-**	**-**	**-**	**-**
Cash and cash equivalents, end of period	**$ -**	**$ -**	**$ -**	**$ -**

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Three Months and Six Months Ended June 30, 2006 and 2005 (all tabular amounts in thousands, except per unit amounts) (unaudited)

1. BASIS OF PRESENTATION

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

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2005. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes thereto for the year ended December 31, 2005.

3. CHANGE IN ACCOUNTING POLICY

Unit Based Compensation

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

As a result of retroactively adopting the fair value method of estimating compensation expense, net income in the first six months of 2005 was increased by $3.2 million, net of non-controlling interest of $0.1 million (three months ended June 30, 2005 – a decrease to net income of $2.0 million, net of non-controlling interest of $0.1 million). Net income per unit for the first six months in 2005 changed from $0.03 to $0.08 (three months ended June 30, 2005 changed from $0.28 to $0.25). The opening 2005 accumulated income was increased by $1.3 million, net of non-controlling interest of $0.03 million. Accordingly, the opening 2005 contributed surplus was also decreased by $1.2 million. There was a $0.07 million decrease in the 2005 opening balance of unitholders' capital relating to the transfer of value from contributed surplus on exercise of unit rights in 2004. The adoption of this policy also had the following impact on the opening balances for the second quarter in 2005: accumulated income increased by $6.5 million, non-controlling interest increased by $0.1 million, contributed surplus decreased by $6.6 million, and unitholders' capital decreased by $0.07 million. There was no impact on cash flow as a result of adopting this policy.

4. LONG-TERM DEBT

	June 30, 2006	December 31, 2005
10.5% senior subordinated notes (US$247)	**$ 275**	$ 288
9.625% senior subordinated notes (US$179,699)	**200,365**	209,511
	$ 200,640	$ 209,799

5. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

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

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. Issue costs are being amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Issued, June 6, 2005	$	100,000
Fair value of conversion feature		(4,800)
Conversion of debentures and amortization of discount		(21,434)
Balance, December 31, 2005		73,766
Conversion of debentures and amortization of discount		(44,202)
Balance, June 30, 2006	$	29,564

6. ASSET RETIREMENT OBLIGATIONS

		Six Months Ended June 30, 2006		Year Ended December 31, 2005
Balance, beginning of period	**$**	**33,010**	$	73,297
Liabilities incurred		**604**		406
Liabilities settled		**(1,153)**		(1,637)
Acquisition of liabilities		**-**		3,410
Disposition of liabilities		**(490)**		(2,117)
Accretion		**1,324**		5,762
Change in estimate		**(221)**		(46,111)
Balance, end of period	**$**	**33,074**	$	33,010

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years with the majority of costs incurred between 2044 and 2057. The undiscounted amount of estimated cash flow required to settle the retirement obligations at June 30, 2006 is $220 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 2.5 percent for the years 2006 to 2008, and 1.5 percent thereafter.

7. UNITHOLDERS' CAPITAL

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

	Number of units	Amount
Balance, December 31, 2004	66,538	$ 515,663
Issued on conversion of debentures	1,549	22,859
Issued on conversion of exchangeable shares	363	5,373
Issued on exercise of trust unit rights[(1)]	369	4,217
Issued pursuant to distribution reinvestment program	464	6,908
Balance, December 31, 2005	69,283	555,020
Issued on conversion of debentures	3,143	43,904
Issued on conversion of exchangeable shares	32	672
Issued on exercise of trust unit rights[(1)]	511	5,467
Issued pursuant to distribution reinvestment program	205	3,973
Balance, June 30, 2006	73,174	$ 609,036

(1) Includes compensation expense transferred from contributed surplus.

8. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price for the five day trading period ending on the record date. The exchange ratio at June 30, 2006 was 1.44424 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

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

	Number of exchangeable shares	Amount
Balance, December 31, 2004 *(restated – note 3)*	1,876	$ 12,936
Exchanged for trust units	(279)	(1,975)
Non-controlling interest in net income	-	1,849
Balance, December 31, 2005	1,597	12,810
Exchanged for trust units	(23)	(160)
Non-controlling interest in net income	-	1,400
Balance, June 30, 2006	1,574	$ 14,050

9. TRUST UNIT RIGHTS INCENTIVE PLAN

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

The Trust recorded compensation expense of $1.8 million for the three months ended June 30, 2006 ($1.0 million in 2005) and $3.6 million for the first six months in 2006 ($2.3 million in 2005) pursuant to rights granted under the Plan (note 3).

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

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

	2006	2005
Expected annual reduction to exercise price	**$2.16**	$1.80
Expected volatility	**23%**	23%
Risk-free interest rate	**3.5%-4.1%**	3.7%
Expected life of unit right (years)	**Various (up to 5 years)**	5

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

	Number of rights	**Weighted average exercise price**[(1)]
Balance, December 31, 2004	3,537	$ 9.60
Granted	2,451	$ 15.01
Exercised	(369)	$ 7.90
Cancelled	(253)	$ 9.83
Balance, December 31, 2005	5,366	$ 10.88
Granted	454	$ 18.37
Exercised	(511)	$ 7.01
Cancelled	(169)	$ 10.62
Balance, June 30, 2006	5,140	$ 10.83

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

The following table summarizes information about the unit rights outstanding at June 30, 2006:

Range of Exercise Prices	Number Outstanding at June 30, 2006	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at June 30, 2006	Weighted Average Exercise Price
$ 4.33 to $ 7.00	1,475	2.2	$ 5.53	800	$ 5.56
$ 7.01 to $10.00	901	3.4	$ 9.36	275	$ 9.38
$10.01 to $13.00	455	3.9	$ 11.45	39	$ 11.15
$13.01 to $16.00	1,855	4.3	$ 14.00	-	-
$16.01 to $22.88	454	4.6	$ 17.46	-	-
$ 4.33 to $22.88	5,140	3.5	$ 10.83	1,114	$ 6.70

10. INTEREST EXPENSE

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

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
Bank loan	**$ 2,311**	$ 2,088	**$ 4,253**	$ 4,332
Amortization of deferred charge	**200**	314	**649**	575
Long-term debt	**6,140**	5,446	**12,535**	9,987
Total interest	**$ 8,651**	$ 7,848	**$ 17,437**	$ 14,894

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
Interest paid	**$ 3,434**	$ 1,766	**$ 16,244**	$ 13,200
Income taxes paid	**$ 1,917**	$ 2,434	**$ 3,538**	$ 4,281

12. FINANCIAL DERIVATIVE CONTRACTS

At June 30, 2006, the Trust had derivative contracts for the following:

Oil	**Period**	**Volume**	**Price**	**Index**
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI
Price collar	Calendar 2007	2,000 bbl/d	US$60.00 – $80.40	WTI
Price collar	Calendar 2007	1,000 bbl/d	US$60.00 – $80.60	WTI

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

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

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil and foreign currency do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method.

Subsequent to June 30, 2006, the Company entered into the following derivative contract:

Foreign Currency	Period	Amount	Floor	Cap
Collar	Calendar 2007	US$5,000,000 per month	CAD/US$1.0835	CAD/US$1.1600

13. COMMITMENTS AND CONTINGENCIES

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

At June 30, 2006, the Trust had natural gas physical sales contracts with third parties as follows:

Gas	Period	Volume	Price
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 - $10.50
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 - $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 - $12.60
Price collar	November 1, 2006 to March 31, 2007	5,000 GJ/d	CAD$8.00 - $ 9.45
Price collar	November 1, 2006 to March 31, 2007	5,000 GJ/d	CAD$8.00 - $ 9.50
Price collar	November 1, 2006 to March 31, 2007	5,000 GJ/d	CAD$8.00 - $10.15

At June 30, 2006 the Trust had operating lease and transportation obligations as detailed below:

		Payments Due Within			
	Total	1 year	2 years	3 years	4 years
Operating leases	$ 7,757	$ 1,903	$ 2,215	$ 1,985	$ 1,654
Transportation agreements	3,021	1,888	1,028	105	-
Total	$ 10,778	$ 3,791	$ 3,243	$ 2,090	$ 1,654

At June 30, 2006, there are outstanding letters of credit aggregating $7.3 million issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value of $7.8 million of the original obligation is recorded as a deferred obligation and is being drawn down over the life of the obligations which continue until October 31, 2008 and which, at June 30, 2006, is recorded at $3,474.

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl
Chairman
Baytex Energy Trust
Independent Businessman

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W. A. Blake Cassidy
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Naveen Dargan
Independent Businessman

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

Dale O. Shwed
President and CEO
Crew Energy Inc.

OFFICERS

Raymond T. Chan
President and CEO

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

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

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVE ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

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

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

ABBREVIATIONS

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

ADVISORY

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