HIGHLIGHTS

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

Highlights of the third quarter in 2006 include:

- Achieved record cash flow of $71.9 million, 4% higher than Q2/06 and 7% higher than Q3/05;
- Increased net income to $42 million for Q3/06 and $127 million for the nine months ended September 30, 2006, compared to $40 million and $45 million, respectively, one year ago;
- Maintained a conservative and sustainable payout ratio of 49% for the third quarter and 51% for the first nine months of 2006; and
- Improved financial flexibility with total net debt reducing to $362 million at September 30, 2006 from $384 million at June 30, 2006 and $418 million at year-end 2005.

FINANCIAL	Three Months Ended			Nine Months Ended	
($ thousands, except per unit amounts)	**September 30, 2006**	**June 30, 2006**	September 30, 2005	**September 30, 2006**	September 30, 2005
			(restated – note 3)		*(restated – note 3)*
Petroleum and natural gas sales	**145,754**	140,163	154,930	**422,148**	384,584
Cash flow from operations (1)	**71,930**	69,465	67,501	**211,143**	161,978
Per unit – basic	**0.98**	0.96	1.00	**2.92**	2.42
– diluted	**0.90**	0.88	0.89	**2.66**	2.23
Cash distributions	**35,219**	36,569	27,495	**108,556**	85,639
Per unit	**0.54**	0.54	0.45	**1.62**	1.35
Net income	**42,040**	56,162	39,524	**127,081**	44,692
Per unit – basic	**0.57**	0.77	0.59	**1.76**	0.67
– diluted	**0.54**	0.73	0.54	**1.63**	0.65
Exploration and development	**35,684**	27,468	39,395	**108,038**	99,446
Net acquisitions (dispositions)	**1,303**	(38)	68,678	**695**	69,434
Total capital expenditures	**36,987**	27,430	108,073	**108,733**	168,880
Long-term notes	**200,694**	200,640	208,935	**200,694**	208,935
Convertible debentures	**21,173**	29,564	82,695	**21,173**	82,695
Bank loan	**130,685**	140,187	188,441	**130,685**	188,441
Other working capital deficiency	**12,295**	4,736	5,482	**12,295**	5,482
Notional marked-to-market liabilities (assets)	**(2,801)**	8,961	21,226	**(2,801)**	21,226
Total net debt	**362,046**	384,088	506,779	**362,046**	506,779

OPERATING	Three Months Ended			Nine Months Ended	
	September 30, 2006	June 30, 2006	September 30, 2005	**September 30, 2006**	September 30, 2005
Daily production					
Light oil & NGL (bbl/d)	**3,594**	3,619	4,063	**3,766**	3,782
Heavy oil (bbl/d)	**21,325**	20,413	20,061	**20,958**	20,326
Total oil (bbl/d)	**24,919**	24,032	24,124	**24,724**	24,108
Natural gas (MMcf/d)	**54.9**	54.7	63.9	**56.7**	60.9
Oil equivalent (boe/d @ 6:1)	**34,074**	33,154	34,780	**34,178**	34,261
Average prices (before hedging)					
WTI oil (US$/bbl)	**70.48**	70.70	63.19	**68.22**	55.40
Edmonton par oil ($/bbl)	**79.17**	78.61	76.51	**75.59**	67.90
BTE light oil & NGL ($/bbl)	**57.94**	57.83	59.24	**55.54**	53.15
BTE heavy oil ($/bbl)	**48.28**	47.10	45.39	**44.44**	37.23
BTE total oil ($/bbl)	**49.68**	48.71	47.74	**46.13**	39.73
BTE natural gas ($/Mcf)	**6.35**	6.68	8.39	**7.16**	7.42
BTE oil equivalent ($/boe)	**46.57**	46.35	48.54	**45.26**	41.14
TRUST UNIT INFORMATION					
TSX (C$)					
Unit Price					
High	**$28.66**	$25.39	$18.60	**$28.66**	$18.60
Low	**$21.50**	$19.72	$13.45	**$16.81**	$12.42
Close	**$23.35**	$24.20	$18.55	**$23.35**	$18.55
Volume traded (thousands)	**23,943**	22,379	22,134	**70,751**	65,947
NYSE (US$) [2]					
Unit Price					
High	**$25.87**	$22.97	N/A	**$25.87**	N/A
Low	**$19.26**	$17.08	N/A	**$16.99**	N/A
Close	**$20.91**	$21.70	N/A	**$20.91**	N/A
Volume traded (thousands)	**5,353**	6,827	N/A	**12,916**	N/A
Units outstanding (thousands) [3]	**76,839**	75,448	70,524	**76,839**	70,524
Foreign ownership	**40%**	38%	30%	**40%**	30%

(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.

Operations Review

Production for the third quarter in 2006 averaged 34,074 boe/d compared to 33,154 boe/d in the second quarter of 2006 and 34,780 boe/d for the same period last year. Third quarter production was higher than in the second quarter of 2006 primarily as a result of increased drilling activities and improved weather conditions. Production rates in the third quarter could have been better except for wetter-than-normal weather during September which continued to hamper fluid trucking and movement of equipment in many of our operating areas. Production in October 2006 was approximately 35,200 boe/d and we expect to average over 35,000 boe/d during the fourth quarter of 2006.

Capital expenditures for the quarter totaled $35.7 million. During this period, Baytex participated in the drilling of 41 (39.4 net) wells, resulting in 34 (33.2 net) oil wells, five (5.0 net) gas wells and two (1.2 net) dry holes. Overall drilling success rate was 95% (97% net).

Heavy oil production averaged 21,325 bbl/d during the third quarter of 2006 compared to 20,413 bbl/d in the second quarter of 2006 and 20,061 bbl/d in the third quarter of 2005. The increase in heavy oil production is a result of our expanded drilling efforts designed to capture the improving heavy oil economics.

Production continued to increase at Celtic, reaching 4,200 boe/d in the third quarter as compared to 4,000 boe/d during the second quarter of 2006 and approximately 1,750 boe/d when the property was acquired by Baytex one year ago. Five oil wells were drilled at Celtic during the third quarter, along with a large number of recompletions of existing wells.

At Seal, cold primary production operations continued at rates of about 650 bbl/d. Baytex plans to drill approximately 10 cold primary horizontal producers and four stratigraphic test wells on its 67,000 acre oil sands leasehold at Seal during the first quarter of 2007. Baytex is also conducting reservoir simulation of both waterflooding and steam injection in several parts of its Seal land position to help determine the enhanced recovery potential of this resource asset.

Natural gas and light oil production rates of 54.9 MMcf/d and 3,594 bbl/d were comparable to second quarter levels. Baytex drilled a total of nine natural gas and light oil wells during the third quarter and plans to drill six wells in the fourth quarter of 2006.

Financial Review

Record cash flow from operations of $71.9 million in the third quarter represented an increase from the $69.5 million generated in the prior quarter. The improvement is primarily a result of the increase in our production relative to second quarter results, and the continued strong oil prices experienced through the third quarter.

Heavy oil pricing improved modestly to an average realized price of $48.28 for the third quarter compared to $47.10 in the prior quarter. We expect that heavy oil differentials in the fourth quarter will be affected by seasonal adjustments. However, the average differentials for the quarter should be smaller than those experienced in the same period in 2005 (41%) and 2004 (43%) due to fundamental changes in the demand and transportation factors affecting Canadian heavy oil production. In addition, the cost of diluents are also changing in our favour which will improve the wellhead prices of our heavy oil.

Natural gas pricing weakened in the third quarter, with realized prices averaging $6.35/Mcf compared to $6.68/Mcf in the second quarter and $8.39/Mcf in the third quarter of 2005. In the short term, we continue to employ an active hedging program to minimize the pricing volatility of this commodity. We believe that over the longer term, the natural gas pricing outlook is positive and will support our ongoing investment plans.

Cash flow for the quarter was positively affected by non-recurring royalty adjustments totaling $1.0 million. These adjustments relate to off-season drilling incentives offered by the province of British Colombia on our Stoddart property, and to certain recovery of prior years' freehold royalties.

The balance sheet of Baytex continued to strengthen over the third quarter, as conversions of outstanding convertible debentures contributed to further reduction of total net debt to $362 million at the end of the quarter, down from $384 million at the end of the second quarter, and $418 million at the end of last year. Baytex has significant financial flexibility with over $150 million in unused credit facilities at the end of the third quarter.

Baytex continues to report some of the lowest payout ratios in the oil and gas income trust sector at 49% for the third quarter and 51% for the first nine months of 2006. We believe that this conservative payout policy is an important part of our long-term strategy as a sustainable trust, as it allows us to fully fund our capital programs and cash distributions from internal sources.

Proposed Federal Tax Changes

On October 31, 2006, the Minister of Finance of Canada announced its proposal to apply a distribution tax on distributions from publicly-traded income trusts. Under the proposal, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. It is not known at this time if or when the proposal will be enacted by Parliament.

Following the Minister's announcement, the market's reaction was immediate and significant, with a widespread sell-off across the entire trust sector that eliminated billions of dollars in unitholder value. Income trusts comprise a significant portion of the public issuers in Canada, and trusts provide an important income stream for individuals, especially retirees and those planning retirement.

Baytex is a member of the Canadian Association of Income Funds ("CAIF") as well as the newly formed Coalition of Canadian Energy Trusts (the "Coalition"). We are concerned with the unilateral approach taken by our federal government and the mischaracterization of the business model of energy trusts and its undesirable impact on the Canadian economy. Action plans have been put together both by CAIF and our Coalition to request the government to take time to consult with us and to implement its decision in a way that does not damage our investors and the Canadian economy. It is our hope that through a due process, the government will gain a clearer understanding of our issues and that together, we can find solutions that will see Canada's energy trusts continue to contribute to the prosperity of our nation.

We encourage our Unitholders to read the full transcript of the government's plan at: www.fin.gc.ca/news06/06-061e.html and consult with their financial and tax advisors regarding potential tax consequences based on their individual circumstances. Unitholders may also express their views directly to the Minister of Finance, whose contact information is available at www.fin.gc.ca/admin/contact-e.html.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
November 7, 2006

Management's discussion and analysis ("MD&A"), dated November 6, 2006, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and nine months ended September 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 third quarter of 2006 decreased by 12% to 3,594 bbl/d from 4,063 bbl/d a year earlier. Heavy oil production increased by 6% to 21,325 bbl/d for the third quarter of 2006 compared to 20,061 bbl/d a year ago. Natural gas production decreased by 14% to 54.9 MMcf/d for the third quarter of 2006 compared to 63.9 MMcf/d for the same period last year. The decrease in natural gas versus year-earlier levels was due both to unanticipated restrictions at third-party gas processing facilities and natural declines.

For the first nine months of 2006, light oil and NGL production of 3,766 bbl/d is consistent with the same period last year. Heavy oil production for the first nine months of 2006 increased to 20,958 bbl/d compared to 20,326 bbl/d for the same period in 2005. Natural gas production decreased by 7% to average 56.7 MMcf/d for the first nine months in 2006 compared to 60.9 MMcf/d for 2005.

Revenue

Petroleum and natural gas sales decreased 6% to $145.8 million for the third quarter of 2006 from $154.9 million for the same period in 2005. For the per sales unit calculations, heavy oil sales for the three months ended September 30, 2006 were 56 bbl/d lower (three months ended September 30, 2005 - 84 bbl/d lower) than the production for the period due to inventory in transit under the Frontier supply agreement. The corresponding number for the nine months ended September 30, 2006 was a decrease of 15 barrels per day (nine months ended September 30, 2005 – a decrease of 22 barrels per day).

	Three Months Ended September 30			
	2006		2005	
	$000s	**$/Unit [1]**	$000s	$/Unit [1]
Oil revenue (barrels)				
Light oil & NGL	**19,157**	**57.94**	22,146	59.24
Heavy oil	**94,478**	**48.28**	83,430	45.39
Derivative contracts gain (loss)	**980**	**0.50**	(17,914)	(9.75)
Total oil revenue	**114,615**	**50.11**	87,662	39.64
Natural gas revenue (Mcf)	**32,119**	**6.35**	49,353	8.39
Total revenue (boe @ 6:1)	**146,734**	**46.88**	137,015	42.92

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

Revenue from light oil and NGL for the third quarter of 2006 decreased 14% from the same period a year ago due to a 12% decrease in production and a 2% decrease in wellhead prices. Revenue from heavy oil increased 13% due to a 6% increase in production in addition to a 6% increase in wellhead prices. Revenue from natural gas decreased 35% as a result of a 14% decrease in production combined with a 24% decrease in wellhead prices.

	Nine Months Ended September 30			
	2006		2005	
	$000s	**$/Unit [1]**	$000s	$/Unit [1]
Oil revenue (barrels)				
Light oil & NGL	**57,093**	**55.54**	54,870	53.15
Heavy oil	**254,105**	**44.44**	206,379	37.23
Derivative contracts gain (loss)	**2,026**	**0.35**	(34,353)	(6.20)
Total oil revenue	**313,224**	**46.43**	226,896	34.51
Natural gas revenue (Mcf)	**110,950**	**7.16**	123,335	7.42
Total revenue (boe @ 6:1)	**424,174**	**45.48**	350,231	37.47

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

For the first nine months of 2006, light oil revenue increased 4% from the same period last year due to increase in wellhead prices. Revenue from heavy oil increased 23% due to a 19% increase in wellhead prices combined with a 3% production increase. Revenue from natural gas decreased 10% compared to the first nine months of 2005 due to a 3% decrease in wellhead prices and a 7% decrease in production.

Royalties

Total royalties increased to $24.4 million for the third quarter of 2006 from $22.6 million in 2005. Total royalties for the third quarter of 2006 were 16.8% of sales compared to 14.6% of sales for the same period in 2005. For the third quarter of 2006, royalties were 14.0% of sales for light oil and NGL, 18.2% for heavy oil and 14.1% for natural gas. These rates compared to 14.4%, 15.0% and 13.9%, respectively, for the same period last year. Royalties are generally based on market index prices realized by the industry in the period. As the market price for heavy oil in the third 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 third quarter was a historical high of 18.2%. A $1.2 million recovery in 2005 for gas cost allowance also contributed to the variance between the two periods.

For the nine months ended September 30, 2006, royalties increased to $66.5 million from $54.6 million for the same period last year. Total royalties for the first nine months of 2006 were 15.8% of sales, compared to 14.2% of sales for the corresponding period a year ago. For the first nine months of 2006, royalties were 14.5% of sales for light oil and NGL, 15.4% for heavy oil and 17.1% for natural gas. These rates compared to 14.7%, 12.7% and 16.6%, 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 $1.0 million in the third quarter of 2006 compared to a realized loss of $17.9 million for the same period in the prior year. Derivative contracts outstanding at September 30, 2006 were marked-to-market with an unrealized gain of $11.8 million.

Operating Expenses

Operating expenses for the third quarter of 2006 increased to $29.1 million from $27.5 million in the corresponding quarter last year. Operating expenses were $9.30 per boe for the third quarter of 2006 compared to $8.61 per boe for the third quarter of 2005. The increase in operating expenses per boe was primarily due to an inflationary environment for fuel and oilfield services. For the third quarter of 2006, operating expenses were $12.44 per barrel of light oil and NGL, $9.26 per barrel of heavy oil and $1.36 per Mcf of natural gas. The operating expenses for the same period a year ago were $10.40, $9.49 and $1.05, respectively.

Operating expenses for the first nine months of 2006 increased to $82.6 million from $77.3 million for the first nine months in 2005. Operating expenses were $8.85 per boe for the first nine months of 2006 compared to $8.27 per boe for the corresponding period of the prior year. For the first nine months of 2006, operating expenses were $10.82 per barrel of light oil and NGL, $9.14 per barrel of heavy oil and $1.24 per Mcf of natural gas versus $10.06, $8.98 and $1.03, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for the third quarter of 2006 were $6.1 million compared to $5.3 million for the third quarter of 2005. These expenses were $1.95 per boe for the third quarter of 2006 compared to $1.67 for the same period in 2005. Transportation expenses were $2.40 per barrel of oil and $0.12 per Mcf of natural gas. The corresponding amounts for 2005 were $2.03 and $0.14, respectively.

Transportation expenses for the nine months ended September 30, 2006 were $18.0 million compared to $16.4 million for the first nine months of 2005. These expenses were $1.93 per boe in 2006 compared to $1.76 in 2005. Transportation expenses were $2.37 per barrel of oil and $0.13 per Mcf of natural gas in the 2006 period, and $2.15 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 third quarter of 2006 increased to $4.9 million from $3.9 million in 2005. On a per sales unit basis, these expenses were $1.56 per boe for the third quarter of 2006 compared to $1.21 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 third quarter of 2006 or 2005.

General and administrative expenses for the first nine months of 2006 were $15.0 million, compared to $11.4 million for the prior year. On a per sales unit basis, these expenses were $1.60 per boe in 2006 and $1.22 per boe in 2005. The increase is attributable to the same factors influencing the third quarter variance. In accordance with our full cost accounting policy, no expenses were capitalized in either 2006 or 2005.

Unit Based Compensation Expenses

Compensation expense related to the Trust's unit rights incentive plan was $1.7 million for the third quarter of 2006 compared to $1.2 million for the third quarter of 2005. For the nine months ended September 30, 2006, compensation expense was $5.3 million compared to $3.5 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 $8.8 million for the third quarter of 2006 from $8.5 million for the same quarter last year, primarily due to the general increase in interest rates.

For the first nine months of 2006, interest expense was $26.2 million compared to $23.4 million for the same period last year. The increase is attributable to the general increase in interest rates and the issuance of the 6.5% convertible debentures in June 2005.

Foreign Exchange

Foreign exchange in the third quarter of 2006 was a loss of $0.1 million compared to a gain of $11.6 million in the prior year. The loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8966 at September 30, 2006 compared to 0.8969 at June 30, 2006. The 2005 gain is based on translation at 0.8613 at September 30, 2005 compared to 0.8159 at June 30, 2005.

Foreign exchange for the first nine months of 2006 was a gain of $9.1 million compared to a gain of $7.6 million in the prior year. The 2006 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8966 at September 30, 2006 compared to 0.8577 at December 31, 2005. The 2005 gain is based on translation at 0.8613 at September 30, 2005 compared to 0.8308 at December 31, 2004.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion for the third quarter of 2006 decreased to $38.3 million from $40.8 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 $12.23 per boe compared to $12.77 per boe for the same quarter in 2005.

Depletion, depreciation and accretion decreased to $113.1 million for the first nine months of 2006 compared to $125.5 million for the same period last year. On a sales-unit basis, the provision for the current period was $12.13 per boe compared to $13.43 per boe for the same period a year earlier.

Income Taxes

Current tax expenses decreased to $1.9 million for the third quarter of 2006 from $2.4 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 $1.8 million Saskatchewan Capital Tax and $0.6 million Large Corporation Tax in the corresponding period in 2005.

Current tax expenses were $5.9 million for the first nine months of 2006 compared to $6.3 million for the same period last year. The current tax expense is comprised of $6.4 million of Saskatchewan Capital Tax reduced by a $0.5 million recovery of Large Corporation Tax. This is compared to expenses of $4.8 million and $1.5 million, respectively, in 2005.

Net Income

Net income for the third quarter of 2006 increased to $42.0 million from $39.5 million for the third quarter in 2005. Lower production and prices during the quarter were more than offset by gains on financial derivatives, decrease in depletion charges and decrease in taxes.

Net income for the first nine months of 2006 at $127.1 million was almost triple that of $44.7 million for the same period in 2005. The variance was the result of higher sales prices, elimination of prior year's 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 September 30, 2006, total net debt excluding notional marked-to-market assets or liabilities was $364.8 million compared to $423.7 million at the end of 2005. Borrowings under Baytex's bank facilities were $130.7 million, with the capacity of the facilities set at $300 million. As at September 30, 2006, $78.0 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 September 30		Nine Months Ended September 30	
($ thousands)	**2006**	2005	**2006**	2005
Land	**1,791**	2,023	**7,840**	6,030
Seismic	**770**	3,019	**1,963**	4,378
Drilling and completion	**28,602**	26,783	**79,255**	69,008
Equipment	**3,266**	7,270	**16,801**	17,629
Other	**1,255**	300	**2,179**	2,401
Total exploration and development	**35,684**	39,395	**108,038**	99,446
Net property acquisitions	**1,303**	68,678	**695**	69,434
Total capital expenditures	**36,987**	108,073	**108,733**	168,880

CONSOLIDATED BALANCE SHEETS

(thousands) (Unaudited)	**September 30, 2006**	December 31, 2005
Assets		
Current assets		
Accounts receivable	**$ 68,647**	$ 73,869
Crude oil inventory	**8,601**	9,984
Financial derivative contracts *(note 14)*	**2,801**	5,183
	80,049	89,036
Deferred charges and other assets	**4,988**	9,038
Petroleum and natural gas properties	**969,033**	969,738
Goodwill	**37,755**	37,755
	$ 1,091,825	$ 1,105,567
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 76,130**	$ 89,966
Distributions payable to unitholders	**13,413**	10,393
Bank loan	**130,685**	123,588
	220,228	223,947
Long-term debt *(note 4)*	**200,694**	209,799
Convertible debentures *(note 5)*	**21,173**	73,766
Asset retirement obligations *(note 6)*	**34,312**	33,010
Deferred obligations *(note 15)*	**2,933**	4,558
Future income taxes	**129,038**	159,745
	608,378	704,825
Non-controlling interest *(note 8)*	**14,928**	12,810
Unitholders' equity		
Unitholders' capital *(note 7)*	**627,432**	555,020
Conversion feature of debentures *(note 5)*	**1,055**	3,698
Contributed surplus	**11,845**	10,332
Accumulated distributions	**(385,762)**	(267,986)
Accumulated income	**213,949**	86,868
	468,519	387,932
	$ 1,091,825	$ 1,105,567

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME

	Three Months Ended September 30		Nine Months Ended September30	
(thousands, except per unit data) (Unaudited)	**2006**	2005	**2006**	2005
		(restated – note 3)		*(restated – note 3)*
Revenue				
Petroleum and natural gas sales	**$ 145,754**	$ 154,930	**$ 422,148**	$ 384,584
Royalties	**(24,421)**	(22,617)	**(66,504)**	(54,629)
Realized gain (loss) on financial derivatives	**980**	(17,914)	**2,026**	(34,353)
Unrealized gain (loss) on financial derivatives	**11,762**	9,535	**(2,382)**	(11,713)
	134,075	123,934	**355,288**	283,889
Expenses				
Operating	**29,105**	27,490	**82,558**	77,304
Transportation	**6,110**	5,323	**17,970**	16,440
General and administrative	**4,870**	3,853	**14,960**	11,393
Unit based compensation *(note 3, 9)*	**1,740**	1,197	**5,292**	3,537
Interest *(note 12)*	**8,773**	8,490	**26,210**	23,384
Foreign exchange loss (gain)	**54**	(11,607)	**(9,105)**	(7,648)
Depletion, depreciation and accretion	**38,285**	40,772	**113,091**	125,548
	88,937	75,518	**250,976**	249,958
Income before income taxes and non-controlling interest	**45,138**	48,416	**104,312**	33,931
Income taxes (recovery) *(note 11)*				
Current	**1,881**	2,355	**5,948**	6,337
Future	**332**	5,603	**(31,002)**	(18,162)
	2,213	7,958	**(25,054)**	(11,825)
Income before non-controlling interest	**42,925**	40,458	**129,366**	45,756
Non-controlling interest *(note 8)*	**(885)**	(934)	**(2,285)**	(1,064)
Net income	**42,040**	39,524	**127,081**	44,692
Accumulated income, beginning of period, as previously reported	**171,909**	7,687	**86,868**	5,694
Accounting policy change for unit based compensation *(note 3)*	**–**	4,473	**–**	1,298
Accumulated income, beginning of period, as restated	**171,909**	12,160	**86,868**	6,992
Accumulated income, end of period	**$ 213,949**	$ 51,684	**$ 213,949**	$ 51,684
Net income per trust unit				
Basic	**$ 0.57**	$ 0.59	**$ 1.76**	$ 0.67
Diluted	**$ 0.54**	$ 0.54	**$ 1.63**	$ 0.65
Weighted average trust units *(note 11)*				
Basic	**73,720**	67,348	**72,307**	66,948
Diluted	**80,522**	76,595	**80,100**	72,774

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September30	
(thousands) (Unaudited)	**2006**	2005	**2006**	2005
		(restated – note 3)		*(restated – note 3)*
Cash provided by (used in):				
Operating activities				
Net income	**$ 42,040**	$ 39,524	**$ 127,081**	$ 44,692
Items not affecting cash:				
Unit based compensation *(note 3, 9)*	**1,740**	1,197	**5,292**	3,537
Amortization of deferred charges	**314**	459	**963**	1,033
Foreign exchange loss (gain)	**54**	(11,607)	**(9,105)**	(7,648)
Depletion, depreciation and accretion	**38,285**	40,772	**113,091**	125,548
Accretion on debentures	**42**	155	**156**	201
Unrealized loss (gain) on financial derivatives *(note 14)*	**(11,762)**	(9,535)	**2,382**	11,713
Future income tax (recovery)	**332**	5,602	**(31,002)**	(18,162)
Non-controlling interest *(note 8)*	**885**	934	**2,285**	1,064
	71,930	67,501	**211,143**	161,978
Change in non-cash working capital	**7,608**	(6,392)	**(7,145)**	(23,605)
Asset retirement expenditures	**(361)**	(233)	**(1,514)**	(1,255)
Decrease (increase) in deferred charges and other assets	**(488)**	401	**(1,466)**	157
	78,689	61,277	**201,018**	137,275
Financing activities				
Increase (decrease) in bank loan	**(9,503)**	79,174	**7,096**	26,997
Payments of distributions	**(35,324)**	(30,241)	**(106,374)**	(90,282)
Issuance of trust units	**3,417**	3,523	**7,082**	6,367
Issuance of convertible debentures *(note 5)*	**–**	–	**–**	100,000
Convertible debentures issue costs *(note 5)*	**–**	–	**–**	(4,250)
	(41,410)	52,456	**(92,196)**	38,832
Investing activities				
Petroleum and natural gas property expenditures	**(37,012)**	(110,871)	**(109,531)**	(171,870)
Disposal of petroleum and natural gas properties	**25**	2,798	**798**	2,990
Change in non-cash working capital	**(292)**	(5,660)	**(89)**	(7,227)
	(37,279)	(113,733)	**(108,822)**	(176,107)
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.

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 from the date at which CICA 3870 was adopted by Baytex, and the financial statements of prior periods have been restated.

As a result of retroactively adopting the fair value method of estimating compensation expense, net income in the first nine months of 2005 was increased by $4.5 million, net of non-controlling interest of $0.1 million (three months ended September 30, 2005 – an increase to net income of $1.3 million, net of non-controlling interest of $0.04 million). Net income per unit for the first nine months in 2005 changed from $0.60 to $0.67 (three months ended September 30, 2005 changed from $0.57 to $0.59). 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 third quarter in 2005: accumulated income increased by $4.5 million, non-controlling interest increased by $0.07 million, contributed surplus decreased by $4.5 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

		September 30, 2006		December 31, 2005
10.5% senior subordinated notes (US$247)	**$**	**276**	$	288
9.625% senior subordinated notes (US$179,699)		**200,418**		209,511
	$	**200,694**	$	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		(52,593)
Balance, September 30, 2006	$	21,173

6. ASSET RETIREMENT OBLIGATIONS

		Nine Months Ended September 30, 2006		Year Ended December 31, 2005
Balance, beginning of period	**$**	**33,010**	$	73,297
Liabilities incurred		**864**		406
Liabilities settled		**(1,514)**		(1,637)
Acquisition of liabilities		**–**		3,410
Disposition of liabilities		**(601)**		(2,117)
Accretion		**1,991**		5,762
Change in estimate		**562**		(46,111)
Balance, end of period	**$**	**34,312**	$	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 costs required to settle the retirement obligations at September 30, 2006 is $221 million. Estimated costs have 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	3,738	52,460
Issued on conversion of exchangeable shares	34	708
Issued on exercise of trust unit rights [1]	1,068	10,862
Issued pursuant to distribution reinvestment program	394	8,382
Balance, September 30, 2006	74,517	$ 627,432

[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 increased monthly by the opening exchange ratio multiplied by 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 September 30, 2006 was 1.47582 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	(24)	(167)
Non-controlling interest in net income	–	2,285
Balance, September 30, 2006	1,573	$ 14,928

9. TRUST UNIT RIGHTS INCENTIVE PLAN

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

The Trust recorded compensation expense of $1.7 million for the three months ended September 30, 2006 ($1.2 million in 2005) and $5.3 million for the first nine months in 2006 ($3.5 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% – 4.5%**	3.3% – 3.8%
Expected life of unit right (years)	**Various [1] (up to 5 years)**	5

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

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

	Number of Unit 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	564	$ 19.41
Exercised	(1,068)	$ 6.63
Cancelled	(189)	$ 10.95
Balance, September 30, 2006	4,673	$ 11.10

[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 September 30, 2006:

Range of Exercise Prices	Number Outstanding at September 30, 2006	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at September 30, 2006	Weighted Average Exercise Price
		(years)			
$ 3.79 to $ 7.00	1,018	2.0	$ 4.97	970	$ 4.93
$ 7.01 to $10.00	908	3.1	$ 8.87	344	$ 8.62
$10.01 to $13.00	352	3.7	$ 11.05	78	$ 11.03
$13.01 to $16.00	2,157	4.1	$ 13.83	6	$ 14.18
$16.01 to $24.59	238	4.7	$ 21.26	–	–
$ 3.79 to $24.59	4,673	3.5	$ 11.10	1,398	$ 6.22

10. NET INCOME PER UNIT

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

	2006	2005
Weighted average number of units outstanding, basic	**72,307**	66,948
Trust units issuable on conversion of exchangeable shares	**2,331**	2,321
Dilutive effect of trust unit incentive rights	**2,574**	1,008
Trust units issuable on conversion of convertible debentures	**2,888**	2,497
Weighted average number of units outstanding, diluted	**80,100**	72,774

The dilutive effect of trust unit incentive rights above did not include 0.2 million trust unit rights (2005 – 1.3 million) because the respective exercise prices exceeded the average market price of the trust units during the year and the amount of compensation expense attributed to future services not yet recognized.

11. INCOME TAXES (RECOVERY)

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

	2006	2005
		(restated – note 3)
Income before income taxes and non-controlling interest	**$ 104,312**	$ 33,931
Expected income taxes at the statutory rate of 37.0% (2005 – 39.6%)	**$ 38,595**	$ 13,427
Increase (decrease) in taxes resulting from:		
Resource allowance	**(4,779)**	(10,740)
Alberta royalty tax credit	**(56)**	(148)
Net income of the Trust	**(39,479)**	(22,855)
Non-taxable portion of foreign exchange gain	**(1,685)**	(1,513)
Effect of change in tax rate	**(22,326)**	1,681
Effect of change in opening tax pool balances	**(1,911)**	(294)
Effect of change in valuation allowance	**1,597**	–
Unit based compensation	**1,958**	1,400
Other	**(2,916)**	880
Large corporation tax and provincial capital tax	**5,948**	6,337
Provision for recovery of income taxes	**$ (25,054)**	$ (11,825)

12. INTEREST EXPENSE

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Bank loan	**$ 2,531**	$ 1,472	**$ 6,784**	$ 5,804
Amortization of deferred charge	**314**	459	**963**	1,034
Long-term debt and convertible debentures	**5,928**	6,559	**18,463**	16,546
Total interest	**$ 8,773**	$ 8,490	**$ 26,210**	$ 23,384

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Interest paid	**$ 13,227**	$ 10,687	**$ 29,471**	$ 23,887
Income taxes paid	**$ 2,125**	$ 2,662	**$ 5,664**	$ 6,943

14. FINANCIAL DERIVATIVE CONTRACTS

At September 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
Collar	Calendar 2007	US$5,000,000 per month	CAD/US$1.0835	CAD/US$1.1600

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

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

15. 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 September 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 September 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	$ 7,297	$ 1,994	$ 2,160	$ 1,985	$ 1,158
Transportation agreements	2,552	1,815	711	26	–
Total	$ 9,849	$ 3,809	$ 2,871	$ 2,011	$ 1,158

Subsequent to September 30, 2006 the Trust entered into additional transportation obligations as detailed below:

	Payments Due Within				
	Total	1 year	2 years	3 years	4 years
Transportation agreements	$ 1,441	$ 396	$ 633	$ 412	$ –

At September 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. At September 30, 2006, $5.2 million of the liability remains, with $2.8 million recorded as deferred obligations and the $2.4 million payable within 12 months included in current liabilities.

In connection with a purchase of properties, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. As at September 30, 2006, an additional $0.5 million was paid for year one's obligations under the agreement and has been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

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

16. SUBSEQUENT EVENT

On October 31, 2006, the Federal Government announced its intention to tax the distributions of income trusts beginning in 2011 at the corporate tax rates. If this legislation is enacted there could potentially be additional future income taxes to be recorded by the Trust. At this time an estimate of the financial effect of the announcement cannot be made.

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
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BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Societe Generale
Union Bank of California

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.