Third Quarter Interim Report to the Unitholders for the period ended September 30, 2007

BAYTEX
ENERGY TRUST

Q3 2007

HIGHLIGHTS OF Q3/2007

- Achieved record production of 38,094 boe/d, reflecting contributions from the Pembina and Lindbergh assets acquired at the end of the second quarter;
- Generated record cash flow of $75 million, 42% higher than the previous quarter;
- Maintained monthly distributions at $0.18 per unit, with sustainable net payout ratios of 52% for the third quarter and 58% for the first nine months of the year;
- Continued successful development at Seal, adding eight new horizontal wells with initial production rates averaging 150 bbl/d per well; and
- Entered into new heavy oil supply contracts to manage volatility of pricing differentials beyond 2007.

FINANCIAL	*Three Months Ended*			*Nine Months Ended*	
($ thousands, except per unit amounts)	**September 30, 2007**	June 30, 2007	September 30, 2006	**September 30, 2007**	September 30, 2006
Petroleum and natural gas sales	**164,228**	127,511	145,754	**421,489**	422,148
Cash flow from operations (1)	**74,957**	52,755	71,930	**187,363**	211,143
Per unit – basic	**0.90**	0.69	0.98	**2.38**	2.92
– diluted	**0.84**	0.65	0.90	**2.23**	2.66
Cash distributions	**38,746**	35,815	35,219	**108,613**	108,556
Per unit	**0.54**	0.54	0.54	**1.62**	1.62
Net Income	**36,674**	31,050	42,040	**91,507**	127,081
Per unit – basic	**0.44**	0.41	0.57	**1.16**	1.76
– diluted	**0.43**	0.39	0.54	**1.12**	1.63
Exploration and development	**43,533**	25,628	35,684	**114,370**	108,038
Acquisitions – net of dispositions	**752**	239,848	1,303	**240,363**	695
Total capital expenditures	**44,285**	265,476	36,987	**354,733**	108,733
Long-term notes	**179,280**	191,355	200,694	**179,280**	200,694
Convertible debentures	**16,531**	17,030	21,173	**16,531**	21,173
Bank loan	**259,328**	257,977	130,685	**259,328**	130,685
Other working capital deficiency	**12,189**	4,798	12,295	**12,189**	12,295
Mark-to-market net liabilities (assets)	**7,027**	7,814	(2,801)	**7,027**	(2,801)
Total net debt	**474,355**	478,974	362,046	**474,355**	362,046

OPERATING	*Three Months Ended*			*Nine Months Ended*	
	September 30, 2007	June 30, 2007	September 30, 2006	**September 30, 2007**	September 30, 2006
Daily production					
Light oil & NGL *(bbl/d)*	**6,556**	3,705	3,594	**4,593**	3,766
Heavy oil *(bbl/d)*	**22,593**	21,444	21,325	**22,057**	20,958
Total oil *(bbl/d)*	**29,149**	25,149	24,919	**26,650**	24,724
Natural gas *(MMcf/d)*	**53.7**	49.3	54.9	**51.2**	56.7
Oil equivalent *(boe/d @ 6:1)*	**38,094**	33,372	34,074	**35,184**	34,178
Average prices (before hedging)					
WTI oil *(US$/bbl)*	**75.38**	65.03	70.48	**66.19**	68.22
Edmonton par oil *($/bbl)*	**80.24**	72.15	79.17	**73.16**	75.59
BTE light oil & NGL *($/bbl)*	**67.82**	54.42	57.94	**60.03**	55.54
BTE heavy oil *($/bbl)*	**45.89**	40.14	48.28	**42.13**	44.44
BTE total oil *($/bbl)*	**50.85**	42.26	49.68	**45.23**	46.13
BTE natural gas *($/Mcf)*	**5.80**	7.02	6.35	**6.72**	7.16
BTE oil equivalent *($/boe)*	**47.06**	42.22	46.57	**44.04**	45.26
TRUST UNIT INFORMATION					
TSX *(C$)*					
Unit price					
High	**$21.45**	$22.92	$28.66	**$22.92**	$28.66
Low	**$16.68**	$20.15	$21.50	**$16.68**	$16.81
Close	**$20.13**	$21.34	$23.35	**$20.13**	$23.35
Volume traded *(thousands)*	**26,365**	20,544	23,943	**68,759**	70,751
NYSE *(US$)* (2)					
Unit price					
High	**$21.03**	$21.18	$25.87	**$21.18**	$25.87
Low	**$15.51**	$17.42	$19.26	**$15.51**	$16.99
Close	**$20.33**	$19.99	$20.91	**$20.33**	$20.91
Volume traded *(thousands)*	**5,315**	3,135	5,353	**12,630**	12,916
Units outstanding *(thousands)* (3)	**86,478**	85,914	76,839	**86,478**	76,839

(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 (see reconciliation under MD&A). 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 trading 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

Capital expenditures for the third quarter of 2007 totaled $43.5 million for exploration and development activities. During the third quarter, Baytex participated in the drilling of 51 (48.6 net) wells, resulting in 38 (36.3 net) oil wells, 10 (9.5 net) gas wells, two (1.8 net) service wells and one (1.0 net) dry hole for a 98.0% (97.9% net) success rate. In addition, 17 wells were drilled by other operators on farm-outs from Baytex, with Baytex retaining overriding royalty interests. Total exploration and development capital expenditures for 2007 is expected to be consistent with previous guidance of approximately $150 million.

Production averaged 38,094 boe/d during the third quarter, a 14% increase over that of the previous quarter. This is in line with expectations due to the acquisition of properties at Pembina and Lindbergh at the end of June. Production at Pembina and Lindbergh averaged approximately 5,000 boe/d during the third quarter, exceeding the 4,500 boe/d production level at the announcement of this transaction in May of this year. Battery and compression modifications conducted in the third quarter have increased operational reliability at Pembina, which, together with improved industry cooperation, bodes well for future consistency of results from this area.

At Seal, eight new horizontal production wells were successfully drilled during the third quarter, continuing our record of 100% success rate in development drilling in this area. The majority of these wells were put on production after the end of the third quarter. Initial production from these wells met the target average rate of 150 bbl/d per well. One of these wells was equipped with tubulars suitable for thermal operations to facilitate the cyclic steam pilot test scheduled to commence in early 2008. We are also planning an active program of development and stratigraphic test drilling in 2008 to follow up on this year's success in the area.

FINANCIAL REVIEW

Cash flow from operations for the third quarter was $75.0 million, an increase of 42% compared to $52.8 million for the second quarter of 2007. The third quarter is the first full quarter of operations that reflects the acquisition of the Pembina and Lindbergh assets. In addition to the increase in production, we received improved oil prices averaging $50.85/bbl in the third quarter compared to $42.26/bbl in the second quarter. This improvement is a result of both the rise in benchmark WTI prices and the increase in higher priced light oil produced at Pembina. Natural gas prices continued to decline in the third quarter as growing storage levels dominated market sentiments. Baytex's average natural gas wellhead price for the third quarter decreased 17% to $5.80/Mcf compared to $7.02/Mcf in the second quarter.

The weakness in the U.S. dollar continues to impact the financial results of all Canadian oil and gas producers. The U.S.-to-Canadian exchange rate has increased from 0.8581 at the end of 2006 to 1.0037 at the end of the third quarter of 2007, which has offset much of the benefit of higher world oil prices and exacerbated the effect of declining natural gas prices. Baytex has partially mitigated this foreign exchange impact through financial derivative contracts and our U.S. dollar denominated debt. As at September 30, 2007, we had an unrealized foreign exchange gain of $31 million primarily relating to our U.S. dollar senior subordinated notes.

Heavy oil pricing differentials continue to reflect fundamental improvements brought on by infrastructure and geopolitical developments in North America. Lloyd Blend differentials averaged 29% both in the third quarter and for the first nine months of this year. Differentials in the fourth quarter are expected to increase commensurate with lower seasonal demand for heavy oil.

Total debt at the end of the third quarter was $474 million, representing 1.6 times third quarter cash flow on an annualized basis. Baytex continues to have a strong balance sheet with ample flexibility and liquidity, with approximately $100 million in undrawn credit facilities.

RISK MANAGEMENT UPDATE

With the upcoming expiry of the Frontier heavy oil supply agreement at the end of 2007, we are pleased to report that Baytex has entered into a portfolio of supply contracts that allow us to continue to mitigate our exposure to cash flow volatility from fluctuations in heavy oil pricing differentials. These contracts, in aggregate, call for the sale of 15,340 bbl/d of blend crude (made up of approximately 75% Baytex raw heavy oil production and 25% diluent) in 2008 and 10,340 bbl/d of blend crude in 2009 at approximately 68% of WTI prices for 2008 and 67% of WTI prices for 2009. Terms of these contracts are summarized in Note 15 of the third quarter financial statements. We believe that these contracts will provide us with a significant level of protection from pricing volatility during the next two years while third party infrastructure is being built to improve the long term access of Canadian heavy crude to the U.S. refining market.

Baytex has consistently employed a comprehensive risk management program to protect its cash flow for distribution and capital investment purposes. We have recently added positions in WTI financial derivative contracts, physical sales contracts for natural gas, and U.S. dollar foreign exchange contracts for 2008. Terms of these contracts are summarized in Notes 14 and 15 of the third quarter financial statements. We will continue to monitor market developments and may increase our hedge positions as conditions warrant.

ALBERTA ROYALTY REVIEW

On October 25, 2007, the Government of Alberta announced changes to the provincial royalty regime. The new regime is effective beginning in 2009, and will increase the province's royalty takes by an estimated 15-20% based on current commodity prices. All product types – conventional oil, natural gas and oil sands – will be subject to higher royalty rates. While we believe that the existing royalty framework requires necessary amendments to reflect the new paradigm of commodity prices, we also believe the announced changes fail to properly recognize the current cost environment for oil and gas exploration and development in Alberta. Furthermore, the new regime represents poor public policy as no consideration is given to the massive capital investments that have been committed to date by the industry, such as our $238 million acquisition completed in June of this year, which are predicated on the economics under the current royalty structure.

Production in Alberta accounts for approximately 40% of the current total production of Baytex. Based on current commodity prices and information available from the government, we estimate that the new royalty regime could reduce our corporate cash flow by approximately 5% in 2009. The two areas which are most affected by the royalty changes are the projects at Pembina and Seal. At Pembina, the majority of our production is from deep wells at high flow rates. Much of the oil production from this area could be subject to the new maximum royalty rate of 50%. Given that the royalty announcement indicates that the government will revamp the Deep Gas Drilling Program to account for the associated high drilling costs, we are working with other operators in the area to encourage the government to broaden their considerations to include deep oil drilling as both are instrumental to the viability of oil and gas development in Alberta. At Seal, our oil sands leases will be subject to modestly higher before and after payout royalty rates beginning in 2009. Nonetheless, rates of return on our Seal development program remain high under the new royalty rates, and we do not envision significant effects on development plans, cash flow or reserves value as a result of the oil sands royalty changes.

The new royalty rates in Alberta will undoubtedly influence our decisions in allocating 2008 and future capital spending. Baytex is fortunate to have a geographically diversified portfolio of investment opportunities and we are committed to generating the highest returns for our investments for the benefits of our stakeholders.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
November 7, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A"), dated November 6, 2007, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and nine months ended September 30, 2007 and the audited consolidated financial statements and MD&A for the year ended December 31, 2006. 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, which represents an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe's may be misleading, particularly if used in isolation.

NON-GAAP FINANCIAL MEASURES

This MD&A refers to certain financial measures, such as payout ratio and cash flow from operations, that are not in accordance with Generally Accepted Accounting Principles ("GAAP") in Canada. These measures do not have any standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. We discuss these measures because we believe that they facilitate the understanding of the results of our operations and financial position.

Production

Light oil and natural gas liquids ("NGL") production for the third quarter of 2007 increased by 82% to 6,556 bbl/d from 3,594 bbl/d a year earlier primarily as a result of the acquisition of the Pembina assets at the end of the second quarter of 2007. Heavy oil production increased 6% to 22,593 bbl/d for the third quarter of 2007 compared to 21,325 bbl/d a year ago, primarily resulting from the Lindbergh property acquisition at the end of the second quarter of 2007. Natural gas production decreased by 2% to 53.7 MMcf/d for the third quarter of 2007 compared to 54.9 MMcf/d for the same period last year. Natural gas production was 9% higher in the third quarter than in the second quarter of 2007 due to the Pembina acquisition.

For the first nine months of 2007, light oil and NGL production increased by 22% to 4,593 bbl/d from 3,766 bbl/d for the same period last year. Heavy oil production for the first nine months in 2007 increased by 5% to 22,057 bbl/d compared to 20,958 bbl/d for the same period in 2006. Natural gas production decreased by 10% to an average 51.2 MMcf/d for the first nine months in 2007 compared to 56.7 MMcf/d for 2006.

Revenue

Petroleum and natural gas sales increased 13% to $164.2 million for the third quarter of 2007 from $145.8 million for the same period in 2006.

For the per sales unit calculations, heavy oil sales for the three months ended September 30, 2007 were 162 bbl/d lower (three months ended September 30, 2006 – 56 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, 2007 was a decrease of 124 bbl/d (nine months ended September 30, 2006 – a decrease of 15 bbl/d).

	Three Months Ended September 30			
	2007		2006	
	$000s	*$/Unit (1)*	*$000s*	*$/Unit (1)*
Oil revenue *(barrels)*				
Light oil & NGL	**40,904**	**67.82**	19,157	57.94
Heavy oil	**94,702**	**45.89**	94,478	48.28
Derivative contracts gain	**583**	**0.28**	980	0.50
Total oil revenue	**136,189**	**51.07**	114,615	50.11
Natural gas revenue *(Mcf)*	**28,622**	**5.80**	32,119	6.35
Total revenue *(boe)*	**164,811**	**47.23**	146,734	46.88

(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 2007 increased 114% from the same period a year ago due to increases in sales volume and wellhead prices. Revenue from heavy oil remained consistent as a 5% decrease in wellhead prices was offset by a 6% increase in volume. Revenue from natural gas decreased 11% as the result of a 2% decrease in volume and a 9% decrease in wellhead prices.

	Nine Months Ended September 30			
	2007		2006	
	$000s	$/Unit (1)	$000s	$/Unit (1)
Oil revenue *(barrels)*				
Light oil & NGL	**75,271**	**60.03**	57,093	55.54
Heavy oil	**252,268**	**42.13**	254,105	44.44
Derivative contracts gain	**1,203**	**0.20**	2,026	0.35
Total oil revenue	**328,742**	**45.40**	313,224	46.43
Natural gas revenue *(Mcf)*	**93,950**	**6.72**	110,950	7.16
Total revenue *(boe)*	**422,692**	**44.16**	424,174	45.48

For the first nine months of 2007, light oil and NGL revenue increased 32% from the same period last year due to an 8% increase in wellhead prices and a 22% increase in volume. Revenue from heavy oil decreased marginally as the increase in volume was offset by a decrease in wellhead prices. Revenue from natural gas decreased 15% compared to the first nine months of 2006 due to a 10% decrease in volume and a 6% decrease in wellhead prices.

Royalties

Total royalties increased to $28.7 million for the third quarter of 2007 from $24.4 million in 2006. Total royalties for the third quarter of 2007 were 17.5% of sales compared to 16.8% of sales for the same period in 2006. For the third quarter of 2007, royalties were 20.1% of sales for light oil, NGL and natural gas, and 15.5% for heavy oil. These rates compared to 14.1% and 18.2%, respectively, for the same period last year. Royalties are generally based on market index prices realized by the industry in the period, with rates increasing as price and volume escalate.

For the nine months ended September 30, 2007, royalties increased to $70.3 million from $66.5 million for the same period last year. Total royalties for the first nine months of 2007 were 16.7% of sales, compared to 15.8% of sales for the corresponding period a year ago. For the first nine months of 2007, royalties were 18.2% of sales for light oil, NGL and natural gas and 15.7% for heavy oil. These rates compared to 16.2% and 15.4%, respectively, for the same period in 2006.

Operating Expenses

Operating expenses for the third quarter of 2007 increased to $37.8 million from $29.1 million in the corresponding quarter last year. Operating expenses were $10.84 per boe for the third quarter of 2007 compared to $9.30 per boe for the third quarter of 2006. For the third quarter of 2007, operating expenses were $10.09 per boe of light oil, NGL and natural gas, and $11.36 per barrel of heavy oil. The operating expenses for the same period a year ago were $9.37 and $9.27, respectively. The increase in operating costs for conventional oil and gas was, in part, due to the higher cost sour operations at Pembina. In general, the inflationary environment has not entirely subsided as certain cost categories such as property taxes, labour costs and fuel costs continued to increase. This is particularly prevalent in heavy oil operating areas as industry activity levels remain strong due to robust economics associated with the current heavy oil pricing environment.

Operating expenses for the first nine months of 2007 increased to $96.0 million from $82.6 million for the first nine months in 2006. Operating expenses were $10.03 per boe for the first nine months of 2007 compared to $8.85 per boe for the corresponding period of the prior year. For the first nine months of 2007, operating expenses were $9.57 per boe of light oil, NGL and natural gas and $10.30 per barrel of heavy oil compared to $8.40 and $9.14, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for the third quarter of 2007 were $6.5 million compared to $6.1 million for the third quarter of 2006. These expenses were $1.86 per boe for the third quarter of 2007 compared to $1.95 for the same period in 2006. Transportation expenses were $0.67 per boe of light oil, NGL and natural gas and $2.68 per barrel of heavy oil. The corresponding amounts for third quarter of 2006 were $0.86 and $2.61, respectively.

Transportation expenses for the nine months ended September 30, 2007 were $21.3 million compared to $18.0 million for the first nine months of 2006. These expenses were $2.23 per boe in 2007 compared to $1.93 in 2006. Transportation expenses were $0.86 per boe of light oil, NGL and natural gas and $3.05 per barrel of heavy oil in the 2007 period, compared to $0.89 and $2.58, respectively, in the 2006 period. The increase in transportation expenses for heavy oil primarily reflects higher fuel costs and longer haul distances, particularly for production at Seal, to access higher value markets.

General and Administrative Expenses

General and administrative expenses for the third quarter of 2007 increased to $5.6 million from $4.9 million in 2006. On a per sales unit basis, these expenses were $1.61 per boe for the third quarter of 2007 compared to $1.56 per boe for the same period in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

General and administrative expenses for the first nine months of 2007 were $16.8 million, compared to $15.0 million for the prior period. On a per sales unit basis, these expenses were $1.75 per boe in 2007 and $1.60 per boe in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either 2007 or 2006.

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $2.4 million for the third quarter of 2007 compared to $1.7 million for the third quarter of 2006. For the nine months ended September 30, 2007, compensation expense was $6.2 million compared to $5.3 million for the same period in 2006.

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 for the third quarter of 2007 increased to $9.3 million compared to $8.8 million for the third quarter of 2006. The decrease in convertible debentures outstanding and the effect of a stronger Canadian dollar on U.S. dollar denominated interest expenses were offset by the increase in bank loans and floating interest rates related to bank borrowings.

For the first nine months of 2007, interest expense was $26.5 million compared to $26.2 million for the same period last year.

Foreign Exchange

Foreign exchange gain in the third quarter of 2007 was $12.3 million compared to a loss of $0.1 million in the third quarter of 2006. The gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0037 at September 30, 2007 compared to 0.9404 at June 30, 2007. The 2006 gain is based on translation at 0.8966 at September 30, 2006 compared to 0.8969 at June 30, 2006.

Foreign exchange gain for the first nine months of 2007 was $31.0 million compared to $9.1 million in the prior year. The 2007 gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0037 at September 30, 2007 compared to 0.8581 at December 31, 2006. The 2006 gain is based on translation at 0.8966 at September 30, 2006 compared to 0.8577 at December 31, 2005.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion for the third quarter of 2007 increased to $51.5 million from $38.3 million for the same quarter in 2006. On a sales-unit basis, the provision for the current quarter was $14.76 per boe compared to $12.23 per boe for the same quarter in 2006. The higher rate is due to increased future development costs reflected in the reserves evaluation as of December 31, 2006, the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Depletion, depreciation and accretion increased to $135.4 million for the first nine months of 2007 compared to $113.1 million for the same period last year. On a sales-unit basis, the provision for the current period was $14.15 per boe compared to $12.13 per boe for the same period a year earlier. The increase is attributable to the same factors influencing the third quarter calculations.

Taxes

On June 22, 2007, the federal government's bill regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received Royal Assent. As a result, a future income tax recovery of $0.5 million was recognized in the second quarter relating to un-utilized tax pools in the Trust which will be deductible to the Trust after 2010. The majority of the Trust's temporary differences resides in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40 percent of that trust's October 31, 2006 market capitalization for 2007, and an additional 20 percent of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2007 and $365 million for each of the subsequent three years.

The provision for future income taxes for the current quarter was a recovery of $3.9 million compared to an expense of $0.3 million in the same period in 2006. For the nine months ended September 30, 2007, the provision for future income taxes was a recovery of $21.7 million compared to a recovery of $31.0 million for the same period in 2006. As a result of the Pembina/Lindbergh acquisition, Baytex recognized a future income tax liability of $69.1 million arising from the difference between the $73.7 million in tax pools acquired and the value assigned to the assets.

Current tax of $1.9 million for the third quarter of 2007 is comprised primarily of Saskatchewan Capital Tax and Resource Surcharge. Current tax for the same period a year ago was $1.9 million which included $2.3 million of Saskatchewan Capital Tax and Resource Surcharge and a $0.4 million recovery of Large Corporation Tax due to the elimination of this tax during the year.

Current tax expenses were $4.6 million for the first nine months of 2007 compared to $5.9 million for the same period last year. The 2007 current tax expense is comprised primarily of Saskatchewan Capital Tax and Resource Surcharge. The 2006 current tax expense included $6.4 million of Saskatchewan Capital Tax and Resource Surcharge and a $0.5 million recovery of Large Corporation Tax.

Net Income

Net income for the third quarter of 2007 was $36.7 million compared to $42.0 million for the third quarter in 2006. The variance was the result of higher operating costs and depletion expenses which were partly offset by a higher foreign exchange gain.

Net income for the first nine months of 2007 was $91.5 million compared to $127.1 million for the same period in 2006. The variance was due to modestly lower commodity prices, higher operating and transportations costs, higher depletion rates, higher unrealized loss on financial derivatives and lower future tax recoveries. These negative factors were partially offset by higher sales volumes and a higher foreign exchange gain.

CASH FLOW FROM OPERATIONS, PAYOUT RATIO AND DISTRIBUTIONS

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Trust's payout ratio is calculated as cash distributions declared divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

	Three Months Ended			*Nine Months Ended*		*Year Ended*	
	September 30, 2007	June 30, 2007	September 30, 2006	**September 30, 2007**	September 30, 2006	December 31, 2006	December 31, 2005
Cash flow from operating activities	**73,722**	52,878	78,689	**186,319**	201,018	261,982	204,639
Change in non-cash working capital	**308**	(956)	(7,608)	**(1,995)**	7,145	9,058	20,212
Asset retirement expenditures	**351**	257	361	**1,311**	1,514	1,747	1,637
Decrease (increase) in deferred charges and other assets	**576**	576	488	**1,728**	1,466	1,875	977
Cash flow from operations	**74,957**	52,755	71,930	**187,363**	211,143	274,662	227,465
Cash distributions declared	**38,746**	35,815	35,219	**108,613**	108,556	143,072	114,221
Payout ratio (1)	**52%**	68%	49%	**58%**	51%	52%	50%

(1) Payout ratio is calculated as cash distributions declared divided by cash flow from operations.

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions of $38.7 million for the third quarter of 2007 were funded through cash flow from operations of $75.0 million. For the nine months ended September 30, 2007, cash distributions of $108.6 million were funded through cash flow from operations of $187.4 million.

The following table compares cash distributions to cash flow from operating activities and net income:

	Three Months Ended September 30,		*Nine Months Ended September 30,*		*Year Ended December 31,*	
	2007	2006	**2007**	2006	2006	2005
Cash flow from operating activities	**73,722**	78,689	**186,319**	201,018	261,982	204,639
Net income	**36,674**	42,040	**91,507**	127,081	147,069	79,876
Actual cash distributions payable	**38,746**	35,219	**108,613**	108,556	143,072	114,221
Excess of cash flow from operating activities over cash distributions paid	**34,976**	43,470	**77,706**	92,462	118,910	90,418
Excess (shortfall) of net income over cash distributions paid	**(2,072)**	6,821	**(17,106)**	18,525	3,997	(34,345)

It is Baytex's long term operating objective to substantially fund cash distributions and capital expenditures required to maintain production and reserves through cash flow from operations. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of temporary decline in commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall will be funded through a combination of equity and debt financing. Currently, Baytex has approximately $100 million in available credit facilities to fund such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the three months ended September 30, 2007, the Trust's cash distributions exceeded net income by $2.1 million. However, net income should be adjusted by $37.1 million of non-cash items that do not impact our cash flow. For the nine months ended September 30, 2007, the Trust's cash distribution exceeded net income by $17.1 million with net income reduced by $94.8 million of non-cash items. Non-cash charges such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions. The Trust's historic finding, development and acquisition costs have been less than our current depletion, depreciation, and accretion provision on a per unit basis.

Liquidity and Capital Resources

At September 30, 2007, total net debt was $474.4 million compared to $364.4 million at the end of 2006. The increase is mainly attributable to the bank loan incurred to partially finance the acquisition of the Pembina and Lindbergh properties at the end of the second quarter. Bank borrowings and working capital deficiency at the end of third quarter 2007 was $271.5 million compared to total credit facilities of $370 million. The syndicated credit facilities were increased from $300 million to $370 million during June 2007.

Corporate Acquisition

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which has interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since June 26, 2007. The acquisition was financed partly by the issuance of equity and partly by bank loan. Subsequent to the acquisition, the private company was amalgamated with Baytex.

CAPITAL EXPENDITURES

Capital expenditures for the first nine months of 2007 and 2006 are summarized as follows:

	Three Months Ended September 30		*Nine Months Ended September 30*	
($ thousands)	**2007**	2006	**2007**	2006
Land	**2,997**	1,791	**6,056**	7,840
Seismic	**155**	770	**1,524**	1,963
Drilling and completion	**31,888**	28,602	**85,065**	79,255
Equipment	**7,339**	3,266	**18,476**	16,801
Other	**1,154**	1,255	**3,249**	2,179
Total exploration and development	**43,533**	35,684	**114,370**	108,038
Corporate acquisition (net of working capital)	**–**	–	**239,884**	–
Property acquisitions	**804**	1,328	**839**	725
Property dispositions	**(52)**	(25)	**(360)**	(30)
Total capital expenditures	**44,285**	36,987	**354,733**	108,733

Changes in Accounting Policies

Effective January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income" and section 3861 "Financial Instruments – Disclosure and Presentation". These standards have been adopted prospectively. See Note 2 to the Consolidated Financial Statements for further detail and the impact on the Trust's financial statements from application of these new standards.

Effective January 1, 2007 the Trust also adopted the recommendation of CICA revised section 1506 "Accounting Changes" and section 3251 "Equity". The revised section 1506 provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors. The revised section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period.

ENVIRONMENTAL REGULATION AND RISK

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company.

On March 8, 2007, the Alberta Government introduced Bill 3, the *Climate Change and Emissions Management Amendment Act*, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Trust and its operations and financial condition.

THE NEW ROYALTY FRAMEWORK

On September 18, 2007, the Royalty Review Panel appointed by the Alberta government released a report entitled "Our Fair Share", providing recommendations on changes to the province's royalty regime. On October 25, 2007, the Alberta government announced the "New Royalty Framework", accepting many of the recommendations by the Royalty Review Panel. Major changes introduced to Alberta's royalty regime effective January 2009 are as follows:

Conventional oil – overall royalty rates will increase from the current maximum of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to $120 per barrel for West Texas Intermediate (WTI) crude.

Natural gas – the Government will eliminate "old" and "new" tiers. Royalty rates, currently 5% to 35% will increase to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at Cdn$16.59/GJ.

Oil Sands – currently, the pre-payout royalty rate is 1%. Under the new system, this rate will increase for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the current regime, once an oil sands project reaches payout, the 1% royalty converts to a 25% net profits interest. Under the new regime, the net profits interest will apply at the rate of 25% when oil is less than $55 per bbl of WTI, and increase for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Raymond Chan, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex (together the "Disclosure Officers"), are responsible for establishing and maintaining disclosure controls and procedures for Baytex. We have designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that all material or potentially material information about the activities of Baytex is made known to us by others within Baytex.

It should be noted that while our Disclosure Officers believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Controls over Financial Reporting

Under the supervision and with participation of Raymond Chan, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex, we conducted an evaluation of the design and effectiveness of our internal control over financial reporting as of December 31, 2006 based on the framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control – Integrated Framework. Based on this evaluation, management concluded that as of December 31, 2006, Baytex did maintain effective internal control over financial reporting.

There were no changes in our internal control over financial reporting during the nine months ended September 30, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

CONSOLIDATED BALANCE SHEETS

(thousands) (Unaudited)	**September 30, 2007**	December 31, 2006
ASSETS		
Current assets		
Accounts receivable	**$ 81,239**	$ 64,716
Crude oil inventory	**11,043**	9,609
Financial derivative contracts *(note 14)*	**1,134**	3,448
	93,416	77,773
Deferred charges and other assets	**–**	4,475
Petroleum and natural gas properties	**1,255,075**	959,626
Goodwill	**37,755**	37,755
	$ 1,386,246	$ 1,079,629
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 89,367**	$ 71,521
Distributions payable to unitholders	**15,104**	13,522
Bank loan	**259,328**	127,495
Financial derivative contracts *(note 14)*	**8,161**	1,055
	371,960	213,593
Long-term debt *(note 4)*	**179,280**	209,691
Convertible debentures *(note 5)*	**16,531**	18,906
Asset retirement obligations *(note 6)*	**45,381**	39,855
Deferred obligations *(note 15)*	**663**	2,391
Future income taxes	**162,605**	118,858
	776,420	603,294
Non-controlling interest *(note 8)*	**19,956**	17,187
UNITHOLDERS' EQUITY		
Unitholders' capital *(note 7)*	**811,040**	637,156
Conversion feature of debentures *(note 5)*	**817**	940
Contributed surplus *(note 9)*	**17,486**	13,357
Deficit	**(239,473)**	(192,305)
	589,870	459,148
	$ 1,386,246	$ 1,079,629

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF INCOME AND COMPREHENSIVE INCOME

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands, except per unit data) (Unaudited)	**2007**	2006	**2007**	2006
Revenue				
Petroleum and natural gas sales	**$ 164,228**	$ 145,754	**$ 421,489**	$ 422,148
Royalties	**(28,680)**	(24,421)	**(70,281)**	(66,504)
Gain (loss) on financial derivatives *(note 14)*	**1,182**	12,742	**(2,853)**	(356)
	136,730	134,075	**348,355**	355,288
Expenses				
Operating	**37,839**	29,105	**96,010**	82,558
Transportation	**6,489**	6,110	**21,326**	17,970
General and administrative	**5,619**	4,870	**16,750**	14,960
Unit based compensation *(note 9)*	**2,370**	1,740	**6,176**	5,292
Interest *(note 12)*	**9,328**	8,773	**26,463**	26,210
Foreign exchange loss (gain)	**(12,263)**	54	**(31,048)**	(9,105)
Depletion, depreciation and accretion	**51,525**	38,285	**135,426**	113,091
	100,907	88,937	**271,103**	250,976
Income before taxes and non-controlling interest	**35,823**	45,138	**77,252**	104,312
Taxes (recovery) *(note 11)*				
Current	**1,934**	1,881	**4,604**	5,948
Future	**(3,895)**	332	**(21,710)**	(31,002)
	(1,961)	2,213	**(17,106)**	(25,054)
Income before non-controlling interest	**37,784**	42,925	**94,358**	129,366
Non-controlling interest *(note 8)*	**(1,110)**	(885)	**(2,851)**	(2,285)
Net income/Comprehensive income	**$ 36,674**	$ 42,040	**$ 91,507**	$ 127,081

CONSOLIDATED STATEMENT OF DEFICIT

Deficit, beginning of period, as previously reported	**$ (230,916)**	$ (173,880)	**$ (192,305)**	$ (181,118)
Cumulative effect of change in accounting policy *(note 2)*	**–**	–	**(10,166)**	–
Deficit, beginning of period, restated	**(230,916)**	(173,880)	**(202,471)**	(181,118)
Net Income	**36,674**	42,040	**91,507**	127,081
Distributions to unitholders	**(45,231)**	(39,973)	**(128,509)**	(117,776)
Deficit, end of period	**$ (239,473)**	$ (171,813)	**$ (239,473)**	$ (171,813)
Net income per trust unit *(note 10)*				
Basic	**$ 0.44**	$ 0.57	**$ 1.16**	$ 1.76
Diluted	**$ 0.43**	$ 0.54	**$ 1.12**	$ 1.63
Weighted average trust units *(note 10)*				
Basic	**83,669**	73,720	**78,601**	72,307
Diluted	**89,272**	80,522	**84,454**	80,100

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands) (Unaudited)	**2007**	2006	**2007**	2006
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income	**$ 36,674**	$ 42,040	**$ 91,507**	$ 127,081
Items not affecting cash:				
Unit based compensation *(note 9)*	**2,370**	1,740	**6,176**	5,292
Amortization of deferred charges *(note 12)*	**–**	314	**–**	963
Foreign exchange gain	**(12,263)**	54	**(31,048)**	(9,105)
Depletion, depreciation and accretion	**51,525**	38,285	**135,426**	113,091
Accretion on debentures	**35**	42	**105**	156
Unrealized loss (gain) on financial derivatives *(note 14)*	**(599)**	(11,762)	**4,056**	2,382
Future income tax (recovery)	**(3,895)**	332	**(21,710)**	(31,002)
Non-controlling interest *(note 8)*	**1,110**	885	**2,851**	2,285
	74,957	71,930	**187,363**	211,143
Change in non-cash working capital	**(308)**	7,608	**1,995**	(7,145)
Asset retirement expenditures	**(351)**	(361)	**(1,311)**	(1,514)
Decrease in deferred charges and other assets	**(576)**	(488)	**(1,728)**	(1,466)
	73,722	78,689	**186,319**	201,018
Financing activities				
Increase in bank loan	**1,351**	(9,503)	**131,833**	7,096
Payments of distributions	**(38,959)**	(35,324)	**(107,194)**	(106,374)
Issue of trust units *(note 7)*	**559**	3,417	**145,858**	7,082
	(37,049)	(41,410)	**170,497**	(92,196)
Investing activities				
Petroleum and natural gas property expenditures	**(43,533)**	(35,684)	**(114,370)**	(108,038)
Acquisitions *(note 3)*	**(804)**	(1,328)	**(240,723)**	(1,493)
Acquisition of working capital *(note 3)*	**–**	–	**(13,229)**	–
Disposal of petroleum and natural gas properties	**52**	25	**360**	798
Change in non-cash working capital	**7,612**	(292)	**11,146**	(89)
	(36,673)	(37,279)	**(356,816)**	(108,822)
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.

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, 2006, except as noted below. 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, 2006.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments and Hedging Activities

Effective January 1, 2007, the Trust adopted the provisions of the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income", section 3861 "Financial Instruments – Disclosure and Presentation" and section 3251 "Equity". The Trust has adopted these standards retrospectively and the comparative interim consolidated financial statements have not been restated. Transitional amounts have been recorded in deficit.

Financial Instruments

A. Classification

All financial instruments must initially be recognized at fair value on the balance sheet. All financial instruments must be classified into one of the following categories: "held for trading financial assets and liabilities", "loans and receivables", "held to maturity investments", "available for sale financial assets" and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification.

The Trust has made the following classifications:

- Cash and cash equivalents are classified as held for trading and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. A gain or loss arising from a change in the fair value is recognized in net income in the current period.
- Accounts receivable are classified as loans and receivables and are initially measured at fair value and subsequently measured at amortized cost. A gain or loss arising from a change in the fair value or the derecognition or impairment of assets is recognized in net income in the period.

- Accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, long term debt, deferred obligations and convertible debentures have been classified as other financial liabilities and are initially recognized at fair value. They are subsequently measured at amortized cost using the effective interest method. A gain or loss is recognized in net income in the period when the financial liability is derecognized or impaired and through the amortization process.
- All derivative instruments have been classified as held for trading and are measured at fair value. A gain or loss arising from a change in the fair value is recognized in net income in the current period.

B. Transaction Costs

The Trust has elected to expense all financial instrument transaction costs immediately.

C. Effective Interest Method

The Trust uses the effective interest method of amortization for the discount on its convertible debentures.

D. Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract if all of the following are met: (1) when their economic characteristics and risks are not closely related to the host contract; (2) a separate instrument with similar terms as the embedded derivative would meet the definition of a derivative; and (3) the hybrid instrument is not measured at fair value. The Company has selected January 1, 2007 as its transition date for accounting for any potential embedded derivatives.

Hedge Accounting

On January 1, 2007, the Trust chose to discontinue hedge accounting on its interest rate swap. Effective January 1, 2007 a financial liability has been recorded on the balance sheet. Any changes in the fair value of the swap are recorded in net income.

Comprehensive Income

Comprehensive income consists of net earnings and other comprehensive income ("OCI"). OCI includes gains and losses on derivatives designated as cash flow hedges, gains and losses arising from changes in fair value of available for sale assets and unrealized gains and losses on translating financial statements of self sustaining foreign operations, all net of tax. Accumulated other comprehensive income is a new equity category comprised of cumulative OCI. The Trust has not engaged in any transactions giving rise to OCI as of this date.

Transitional Adjustment

The impact of adopting these standards as at January 1, 2007 is as follows:

	As at December 31, 2006	*Adjustment upon adoption of new standards*	*As at January 1, 2007*
Assets			
Deferred charges	$ 4,475	**$ (4,475)**	$ –
Liabilities			
Financial derivative contracts	1,055	$ 5,976	7,031
Future income taxes	118,858	(3,290)	115,568
		2,686	
Unitholders' Equity			
Unitholders' capital	637,156	3,005	640,161
Deficit	(192,305)	(10,166)	(202,471)
		(7,161)	
		$ (4,475)	

Accounting Changes

Effective January 1, 2007, the Trust adopted the recommendation of CICA revised section 1506 "Accounting Changes". The new standard provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors.

Future Accounting Changes

On December 1, 2006, the CICA issued three new accounting standards:

Handbook Section 1535, Capital Disclosures, Section 3862, Financial instruments – Disclosures, and Section 3863, Financial instruments – Presentation. These new standards will be effective on January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks.

3. ACQUISITION

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which has interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition		
Cash paid for property, plant and equipment	$	238,203
Cash paid for working capital		13,229
Costs associated with acquisition		1,681
Total purchase price	$	253,113
Allocation of purchase price		
Working capital	$	13,229
Property, plant and equipment		311,213
Future income taxes		(69,090)
Asset retirement obligations		(2,239)
Total net assets acquired	$	253,113

Amendments may be made to the purchase equation as the cost estimates and balance are finalized.

4. LONG-TERM DEBT

	September 30, 2007	December 31, 2006
10.5% senior subordinated notes (US$247)	**$ 246**	$ 288
9.625% senior subordinated notes (US$179,699)	**179,034**	209,403
	$ 179,280	$ 209,691

The Company has US$247,000 senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The US$179.7 million of 9.625% senior subordinated notes, due July 15, 2010, are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2007 at 104.813%, 2008 at 102.406%, 2009 and thereafter at 100%. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2% until the maturity of these notes.

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. The debt portion will accrete up to the principal balance at maturity. The accretion, and the interest paid are expensed as interest expense in the consolidated statement of income. 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.

	Principal Amount of Debentures	*Book Value of Debentures*	*Book Value of Conversion Feature*
Balance, December 31, 2005	$ 77,152	$ 73,766	$ 3,698
Conversion	(57,533)	(55,049)	(2,758)
Accretion	–	189	–
Balance, December 31, 2006	19,619	18,906	940
Conversion	(2,571)	(2,480)	(123)
Accretion	–	105	–
Balance, September 30, 2007	$ 17,048	$ 16,531	$ 817

6. ASSET RETIREMENT OBLIGATIONS

	Nine Months Ended September 30, 2007	Year Ended December 31, 2006
Balance, beginning of period	**$ 39,855**	$ 33,010
Liabilities incurred	**1,336**	1,199
Liabilities acquired	**2,239**	–
Liabilities settled	**(1,311)**	(1,747)
Disposition of liabilities	**(107)**	(122)
Accretion	**2,518**	2,678
Change in estimate (1)	**851**	4,837
Balance, end of period	**$ 45,381**	$ 39,855

(1) Change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. The undiscounted amount of estimated cash flow required to settle the retirement obligations at September 30, 2007 is $260 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 5.0% for the year 2007, 4.0% for 2008, 3.0% for 2009 and 2.0% thereafter.

7. UNITHOLDERS' CAPITAL

Trust Units

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

	Number of units	Amount
Balance, December 31, 2005	69,283	$ 555,020
Issued on conversion of debentures	3,901	54,799
Issued on conversion of exchangeable shares	34	720
Issued on exercise of trust unit rights	1,250	8,509
Transfer from contributed surplus on exercise of trust unit rights	–	4,434
Issued pursuant to distribution reinvestment program	654	13,674
Balance, December 31, 2006	75,122	637,156
Issued from treasury for cash	7,000	141,886
Issued on conversion of debentures	174	2,603
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	586	4,381
Transfer from contributed surplus on exercise of trust unit rights	–	2,047
Issued pursuant to distribution reinvestment program	1,027	19,732
Cumulative effect of change in accounting policy *(Note 2)*	–	3,005
Balance, September 30, 2007	83,921	$ 811,040

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 September 30, 2007 was 1.63347 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, 2005	1,597	$ 12,810
Exchanged for trust units	(24)	(208)
Non-controlling interest in net income	–	4,585
Balance, December 31, 2006	1,573	17,187
Exchanged for trust units	(7)	(82)
Non-controlling interest in net income	–	2,851
Balance, September 30, 2007	1,566	$ 19,956

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 rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the 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, subject to certain performance criteria.

The Trust recorded compensation expense of $2.4 million for the three months ended September 30, 2007 ($1.7 million in 2006) and $6.2 million for the first nine months in 2007 ($5.3 million in 2006) pursuant to rights granted under the Plan.

Effective January 1, 2006, the Trust 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:

	Nine Months Ended **September 30, 2007**	*Year Ended* December 31, 2006
Expected annual right's exercise price reduction	**$ 2.16**	$ 2.16
Expected volatility	**28%**	23% – 28%
Risk-free interest rate	**3.77% – 4.50%**	3.54% – 4.45%
Expected life of right *(years)*	**Various** (1)	Various (1)

(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 outstanding and exercise prices are detailed below:

	Number of rights	*Weighted average exercise price* (1)
Balance, December 31, 2005	5,366	$ 10.88
Granted	2,443	$ 21.66
Exercised	(1,250)	$ 6.81
Cancelled	(246)	$ 11.54
Balance, December 31, 2006	6,313	$ 14.00
Granted	848	$ 20.50
Exercised	(586)	$ 7.48
Cancelled	(387)	$ 16.71
Balance, September 30, 2007	6,188	$ 13.75

(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, 2007:

Range of Exercise Prices	*Number Outstanding at September 30, 2007*	*Weighted Average Remaining Term (years)*	*Weighted Average Exercise Price*	*Number Exercisable at September 30, 2007*	*Weighted Average Exercise Price*
$ 1.63 to $ 5.00	609	1.0	$ 2.82	609	$ 2.82
$ 5.01 to $ 8.50	789	2.1	$ 6.74	589	$ 6.58
$ 8.51 to $12.00	1,561	3.0	$ 10.72	535	$ 10.55
$12.01 to $15.50	511	3.2	$ 13.29	123	$ 13.20
$15.51 to $19.00	427	4.2	$ 18.25	26	$ 17.91
$19.01 to $22.43	2,291	4.2	$ 20.39	27	$ 21.24
$ 1.63 to $22.43	6,188	3.2	$ 13.75	1,909	$ 7.28

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2005	$ 10,332
Compensation expense	7,460
Transfer from contributed surplus on exercise of trust unit rights (1)	(4,435)
Balance, December 31, 2006	13,357
Compensation expense	6,176
Transfer from contributed surplus on exercise of trust unit rights (1)	(2,047)
Balance, September 30, 2007	$ 17,486

(1) Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

10. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, 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:

Three Months Ended	**September 30, 2007**			September 30, 2006		
	Net income	*Trust units*	*Net income per unit*	*Net income*	*Trust units*	*Net income per unit*
Net income per basic unit	**$ 36,674**	**83,669**	**$ 0.44**	$ 42,040	73,720	$ 0.57
Dilutive effect of trust unit rights	**–**	**1,874**		–	2,646	
Conversion of convertible debentures	**199**	**1,172**		305	1,834	
Exchange of exchangeable shares	**1,110**	**2,557**		885	2,322	
Net income per diluted unit	**$ 37,983**	**89,272**	**$ 0.43**	$ 43,230	80,522	$ 0.54

Nine Months Ended	**September 30, 2007**			September 30, 2006		
	Net income	*Trust units*	*Net income per unit*	*Net income*	*Trust units*	*Net income per unit*
Net income per basic unit	**$ 91,507**	**78,601**	**$ 1.16**	$ 127,081	72,307	$ 1.76
Dilutive effect of trust unit rights	**–**	**2,068**		–	2,574	
Conversion of convertible debentures	**622**	**1,226**		1,412	2,888	
Exchange of exchangeable shares	**2,851**	**2,559**		2,285	2,331	
Net income per diluted unit	**$ 94,980**	**84,454**	**$ 1.12**	$ 130,778	80,100	$ 1.63

The dilutive effect of trust unit rights for the nine months ended September 30, 2007 did not include 2.6 million trust unit rights (2006 – $0.2 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services not yet recognized exceeded the average market price of the trust units during the period.

11. INCOME TAXES (RECOVERY)

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

	Nine Months Ended September 30	
	2007	2006
Income before income taxes and non-controlling interest	$ 77,252	$ 104,312
Expected income taxes at the statutory rate of 34.02% (2006 – 37.00%)	26,282	38,595
Increase (decrease) in taxes resulting from:		
Resource allowance	–	(4,779)
Alberta royalty tax credit	–	(56)
Net income of the Trust	(46,090)	(39,479)
Non-taxable portion of foreign exchange gain	(5,173)	(1,685)
Effect of change in tax rate	1,962	(22,326)
Effect of change in opening tax pool balances	(1,017)	(1,911)
Unit based compensation	2,101	1,958
Other	225	(1,319)
Current taxes	4,604	5,948
Recovery of income taxes	$ (17,106)	$ (25,054)

On June 22, 2007, Bill C-52 Budget Implementation Act which contains legislative provisions to tax publicly traded income trusts in Canada received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted an additional future tax recovery of $0.5 million has been recorded.

12. INTEREST EXPENSE

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	2007	2006
Bank loan and miscellaneous financing	$ 3,973	$ 2,531	$ 9,509	$ 6,784
Amortization of deferred charge	–	314	–	963
Convertible debentures	316	484	987	2,242
Long-term debt	5,039	5,444	15,967	16,221
Total interest	$ 9,328	$ 8,773	$ 26,463	$ 26,210

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	2007	2006
Interest paid	$ 14,232	$ 13,227	$ 29,981	$ 29,471
Income taxes paid	$ 2,208	$ 2,125	$ 7,194	$ 5,664

14. FINANCIAL DERIVATIVE CONTRACTS

At September 30, 2007, the Trust had the following derivative contracts:

OIL	*Period*	*Volume*	*Price*	*Index*
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
Price collar	Calendar 2008	2,000 bbl/d	US$60.00 – $80.25	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $77.05	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $80.10	WTI

FOREIGN CURRENCY	*Period*	*Amount*	*Floor*	*Cap*
Collar	Calendar 2007	US$5,000,000 per month	CAD/US$1.0835	CAD/US$1.1600

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

The financial derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	Three Months Ended September 30		*Nine Months Ended September 30*	
	2007	2006	**2007**	2006
Realized gain on financial derivatives	**$ 583**	$ 980	**$ 1,203**	$ 2,026
Unrealized gain (loss) on financial derivatives	**599**	11,762	**(4,056)**	(2,382)
	$ 1,182	$ 12,742	**$ (2,853)**	$ (356)

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 settled on a monthly basis. The contract is for an initial term of five years commencing January 1, 2003.

At September 30, 2007, the Trust had the following natural gas physical sales contracts:

GAS	*Period*	*Volume*	*Price*
Price collar	April 1, 2007 to October 31, 2007	5,000 GJ/d	$6.65 – $9.15
Price collar	April 1, 2007 to October 31, 2007	5,000 GJ/d	$6.65 – $9.30
Price collar	April 1, 2007 to October 31, 2007	2,500 GJ/d	$6.65 – $8.25
Price collar	April 1, 2007 to October 31, 2007	2,000 GJ/d	$6.65 – $8.30
Price collar	April 1, 2007 to October 31, 2007	2,500 GJ/d	$6.65 – $8.73
Price collar	November 1, 2007 to March 31, 2008	2,500 GJ/d	$6.65 – $8.60
Price collar	November 1, 2007 to March 31, 2008	2,500 GJ/d	$6.65 – $9.00
Price collar	November 1, 2007 to March 31, 2008	2,500 GJ/d	$6.65 – $8.05

Subsequent to September 30, 2007, the Trust entered into the following natural gas physical sales contracts:

GAS	*Period*	*Volume*	*Price*
Price collar	Calendar 2008	5,000 GJ/d	$6.15 – $7.00
Price collar	Calendar 2008	5,000 GJ/d	$6.15 – $7.46

Subsequent to September 30, 2007, the Trust entered into four long-term crude oil supply contracts with third parties that require the delivery of 15,340 barrels per day of crude oil in 2008 and 10,340 in 2009. The details of these contracts are:

HEAVY OIL	*Period*	*Volume*	*Price*
Price Swap – WCS Blend	Calendar 2008	13,340 bbl/d	WTI x 67.1% (weighted average)
Price Swap – LLB Blend	Calendar 2008	2,000 bbl/d	WTI less US$24.55
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)

Subsequent to September 30, 2007, the Trust entered into a foreign exchange contract for the period January 1, 2008 to June 30, 2008 for the sale of US$10 million per month at a rate of 0.9935. This contract is extendable on similar terms on June 30, 2008, at the option of the counterparty, for a further six months to the end of 2008.

At September 30, 2007, the Trust had operating lease and transportation obligations as summarized below:

($ thousands)		*Payments Due Within*				
	Total	*1 year*	*2 years*	*3 years*	*4 years*	*5 years*
Operating leases	$ 6,605	$ 2,460	$ 2,460	$ 1,441	$ 130	$ 114
Processing and transportation agreements	24,681	6,942	6,028	5,392	5,021	1,298
Total	$ 31,286	$ 9,402	$ 8,488	$ 6,833	$ 5,151	$ 1,412

OTHER

At September 30, 2007, there were outstanding letters of credit aggregating $7.4 million (September 30, 2006 – $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 being drawn down over the life of the obligations, which continue until October 2008. The fair value of the remaining obligation at September 30, 2007 was $3.0 million, of which $2.5 million was 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. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at September 30, 2007, an additional $0.7 million was paid for year two's obligations ($0.5 million was paid for year one) 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.

ADVISORY AND ABBREVIATIONS

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 reserves 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.

ABBREVIATIONS

bbl	barrel
bbl/d	barrel per day
Bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMboe	million barrels of oil equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGL	natural gas liquids

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl (2)(3)(4)
Chairman of the Board
Independent Businessman

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

Raymond T. Chan
President and CEO
Baytex Energy Trust

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Dale O. Shwed (1)(3)
President and CEO
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Governance Committee

OFFICERS

Raymond T. Chan
President and
Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Anthony W. Marino
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Heavy Oil

Brett J. McDonald
Vice President, Land

R. Shaun Paterson
Vice President, Marketing

Mark F. Smith
Vice President,
Conventional Oil & Gas

Shannon M. Gangl
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Bank of Nova Scotia
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE