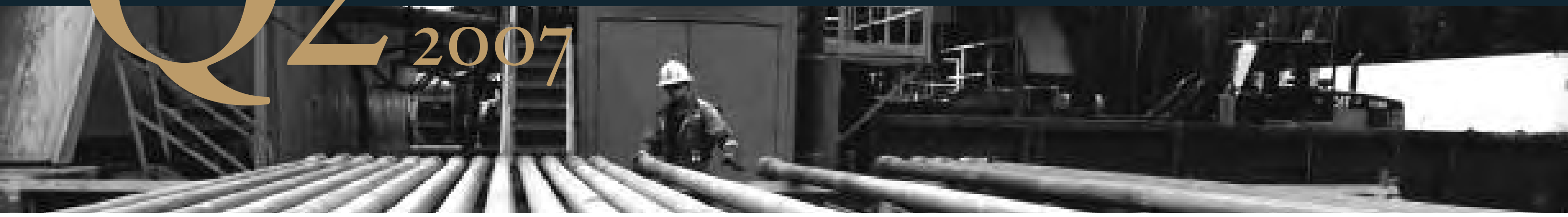
Second Quarter Interim Report to the Unitholders for the period ended June 30, 2007

BAYTEX
ENERGY TRUST

Q2 2007



HIGHLIGHTS OF Q2/2007

- Completed the acquisition of properties located primarily in the Pembina and Lindbergh areas of Alberta, adding production and reserves at accretive metrics and diversifying product mix;
- Closed an equity financing for gross proceeds of $149.5 million;
- Increased bank facilities to $370 million;
- Generated cash flow of $52.8 million and net income of $31.1 million in the quarter; and
- Maintained monthly distributions at $0.18 per unit, with sustainable net payout ratios of 68% for the second quarter and 62% for the first half of 2007.

FINANCIAL	*Three Months Ended*			*Six Months Ended*	
($ thousands, except per unit amounts)	**June 30, 2007**	March 31, 2007	June 30, 2006	**June 30, 2007**	June 30, 2006
Petroleum and natural gas sales	**127,511**	129,750	140,163	**257,261**	276,394
Cash flow from operations (1)	**52,755**	59,651	69,645	**112,406**	139,213
Per unit – basic	**0.69**	0.79	0.96	**1.48**	1.94
– diluted	**0.65**	0.74	0.88	**1.39**	1.79
Cash distributions	**35,815**	34,052	36,569	**69,867**	73,337
Per unit	**0.54**	0.54	0.54	**1.08**	1.08
Net income	**31,050**	23,783	56,162	**54,833**	85,041
Per unit – basic	**0.41**	0.32	0.77	**0.72**	1.19
– diluted	**0.39**	0.30	0.73	**0.70**	1.13
Exploration and development	**25,628**	45,209	27,468	**70,837**	72,354
Acquisitions – net of dispositions	**239,848**	(237)	(38)	**239,611**	(608)
Total capital expenditures	**265,476**	44,972	27,430	**310,448**	71,746
Long-term notes	**191,355**	207,460	200,640	**191,355**	200,640
Convertible debentures	**17,030**	17,643	29,564	**17,030**	29,564
Bank loan	**257,977**	141,387	140,187	**257,977**	140,187
Other working capital deficiency	**4,798**	15,057	4,736	**4,798**	4,736
Notional mark-to-market net liabilities	**7,814**	4,198	8,961	**7,814**	8,961
Total net debt	**478,974**	385,745	384,088	**478,974**	384,088

OPERATING	Three Months Ended			Six Months Ended	
	June 30, 2007	March 31, 2007	June 30, 2006	**June 30, 2007**	June 30, 2006
Daily production					
Light oil & NGL *(bbl/d)*	**3,705**	3,484	3,619	**3,595**	3,853
Heavy oil *(bbl/d)*	**21,444**	22,129	20,413	**21,785**	20,771
Total oil *(bbl/d)*	**25,149**	25,613	24,032	**25,380**	24,624
Natural gas *(MMcf/d)*	**49.3**	50.6	54.7	**50.0**	57.6
Oil equivalent *(boe/d @ 6:1)*	**33,372**	34,041	33,154	**33,705**	34,231
Average prices (before hedging)					
WTI oil *(US$/bbl)*	**65.03**	58.16	70.70	**61.60**	67.09
Edmonton par oil *($/bbl)*	**72.15**	67.09	78.61	**69.62**	73.80
BTE light oil & NGL *($/bbl)*	**54.42**	51.08	57.83	**52.81**	54.40
BTE heavy oil *($/bbl)*	**40.14**	40.17	47.10	**40.15**	42.45
BTE total oil *($/bbl)*	**42.26**	41.66	48.71	**41.95**	44.32
BTE natural gas *($/Mcf)*	**7.02**	7.43	6.68	**7.23**	7.56
BTE oil equivalent *($/boe)*	**42.22**	42.38	46.35	**42.30**	44.60
TRUST UNIT INFORMATION					
TSX *(C$)*					
Unit Price					
High	**$22.92**	$22.28	$25.39	**$22.92**	$25.39
Low	**$20.15**	$18.83	$19.72	**$18.83**	$16.81
Close	**$21.34**	$20.32	$24.20	**$21.34**	$24.20
Volume traded *(thousands)*	**20,544**	21,850	22,379	**42,394**	46,808
NYSE *(US$)* (2)					
Unit Price					
High	**$21.18**	$18.48	$22.97	**$21.18**	$22.97
Low	**$17.42**	$16.01	$17.08	**$16.01**	$16.99
Close	**$19.99**	$17.67	$21.70	**$19.99**	$21.70
Volume traded *(thousands)*	**3,135**	4,180	6,827	**7,315**	7,563
Units outstanding *(thousands)* (3)	**85,914**	78,290	75,448	**85,914**	75,448

(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.

ACQUISITION UPDATE

The acquisition of properties at Pembina and Lindbergh was completed on June 26, 2007. Accordingly, operating results from these properties have been included herein since that date. Total production acquired was approximately 4,500 boe/d, comprised of 2,200 bbl/d of light oil and NGL, 1,000 bbl/d of heavy oil and 8.0 MMcf/d of natural gas. Baytex plans to initiate development activities on these new assets in the third quarter of 2007.

Exploration and development capital spending is projected to be between $150 million and $155 million for 2007. With the impact of this acquisition and the ongoing capital program, Baytex anticipates that production for the third quarter should average between 38,000 and 38,500 boe/d. Based on prevailing commodity prices, cash flow from operations for the quarter is estimated to be in the $70 million to $75 million range, and should be sufficient to substantially fund cash distributions and the planned capital expenditures.

OPERATIONS REVIEW

Capital expenditures for the second quarter of 2007 totaled $266 million, with $26 million spent on exploration and development activities and $240 million spent to acquire the Pembina and Lindbergh assets.

During the second quarter, Baytex participated in the drilling of 24 (22.7 net) wells, resulting in 23 (21.7 net) oil wells and one (1.0 net) dry hole for a 95.8% (95.6% net) success rate. In addition, one well was drilled by another operator on a farm-out from Baytex, with Baytex retaining an overriding royalty interest. All but two of the wells drilled in the second quarter were in Baytex's core heavy oil operating areas near Lloydminster.

Production was in line with expectations and similar to the second quarter of 2006. Baytex typically reports its lowest production in the second quarter due to gas plant turnarounds and spring break-up related hauling restrictions. Heavy oil production was approximately 700 bbl/d lower in the second quarter of 2007 compared to the first quarter largely driven by wet weather and municipal road restrictions that impaired fluid hauling.

At Seal, nine new horizontal production wells were drilled and put on stream near the end of the first quarter. Initial production of these wells met the expected average rate of 150 bbl/d per well. Together with the eight production wells drilled in prior years, production at Seal averaged 1,614 bbl/d during the second quarter of 2007. The second half of this year's drilling program in this area has just begun, with eight horizontal wells planned, one of which will be equipped for thermal operations with testing scheduled to commence in early 2008. Baytex is encouraged by the results at Seal and is planning an active program in 2008 to follow up on this year's success in the area.

FINANCIAL REVIEW

Cash flow from operations for the second quarter was $52.8 million compared to $59.7 million for the first quarter of 2007. Second quarter cash flow was impaired by the seasonal reduction in production and a weaker natural gas price environment. While the benchmark WTI oil price strengthened in the second quarter, averaging US$65.03/bbl compared to US$58.16 in the previous quarter, the strength of the Canadian dollar, which averaged US$0.9106 compared to US$0.8535 in the first quarter, negated much of the benefits of higher world oil prices from the standpoint of a Canadian producer. Natural gas prices continued to be volatile in the quarter as growing storage levels dominated market sentiments. Baytex's average natural gas wellhead price for the second quarter decreased 6% to $7.02/Mcf compared to $7.43/Mcf in the first quarter mainly due to the expiration of higher price sales contracts in place during the winter months.

Heavy oil pricing differentials continue to reflect fundamental improvements brought on by infrastructure and geopolitical developments in North America. Lloyd Blend differentials averaged 29% in the second quarter this year and 28% in the first six months. Differentials in the third quarter are expected to remain in the similar range. Baytex is well positioned to benefit from the improving heavy oil pricing environment.

The acquisition of the Pembina/Lindbergh properties was partially financed by the net proceeds of $141 million from the issue of 7.0 million trust units from treasury. Total debt at the end of the second quarter was $479 million and represents 1.6 to 1.7 times the forecast cash flow of the third quarter on an annualized basis. Concurrent with the closing of the acquisition, Baytex's syndicated credit facilities has been increased to $370 million. Baytex continues to have a strong balance sheet with ample liquidity, with over $100 million in un-drawn credit capacity.

On behalf of the Board of Directors,

Raymond T. Chan, CA
President and Chief Executive Officer
August 8, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A"), dated August 7, 2007, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and six months ended June 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.

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

Production

Light oil and natural gas liquids ("NGL") production for the second quarter of 2007 increased by 2% to 3,705 bbl/d from 3,619 bbl/d a year earlier. Heavy oil production increased 5% to 21,144 bbl/d for the second quarter of 2007 compared to 20,413 bbl/d a year ago. Natural gas production decreased by 10% to 49.3 MMcf/d for the second quarter of 2007 compared to 54.7 MMcf/d for the same period last year. Natural gas production was 3% lower in the second quarter than in the first quarter of 2007.

For the first half of 2007, light oil and NGL production decreased by 7% to 3,595 bbl/d from 3,853 bbl/d for the same period last year. Heavy oil production for the first six months in 2007 increased by 5% to 21,785 bbl/d compared to 20,771 bbl/d for the same period in 2006. Natural gas production decreased by 13% to average 50.0 MMcf/d for the first six months in 2007 compared to 57.6 MMcf/d for 2006.

Revenue

Petroleum and natural gas sales decreased 9% to $127.5 million for the second quarter of 2007 from $140.1 million for the same period in 2006.

For the per sales unit calculations, heavy oil sales for the three months ended June 30, 2007 were 183 bbl/d lower (three months ended June 30, 2006 – 80 bbl/d higher) than the production for the period due to inventory in transit under the Frontier supply agreement.

	Three Months Ended June 30			
	2007		2006	
	$000s	*$/Unit (1)*	*$000s*	*$/Unit (1)*
Oil revenue *(barrels)*				
Light oil & NGL	**18,349**	**54.42**	19,047	57.83
Heavy oil	**77,658**	**40.14**	87,835	47.10
Derivative contracts gain	**91**	**0.05**	903	0.48
Total oil revenue	**96,098**	**42.30**	107,785	49.12
Natural gas revenue *(Mcf)*	**31,504**	**7.02**	33,281	6.68
Total revenue *(boe)*	**127,602**	**42.02**	141,066	46.64

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

Revenue from light oil and NGL for the second quarter of 2007 decreased 4% from the same period a year ago primarily due to a decline in wellhead prices. Revenue from heavy oil decreased 12% as the result of a 15% decrease in wellhead prices which was partially offset by a 5% increase in production. Revenue from natural gas decreased 5% as the result of a 10% decrease in production partially offset by a 5% increase in wellhead prices.

	Six Months Ended June 30			
	2007		2006	
	$000s	*$/Unit* (1)	*$000s*	*$/Unit* (1)
Oil revenue *(barrels)*				
Light oil & NGL	**34,367**	**52.81**	37,937	54.40
Heavy oil	**157,566**	**40.15**	159,627	42.45
Derivative contracts gain	**620**	**0.16**	1,046	0.28
Total oil revenue	**192,553**	**42.09**	198,610	44.55
Natural gas revenue *(Mcf)*	**65,328**	**7.23**	78,830	7.56
Total revenue *(boe)*	**257,881**	**42.40**	277,440	44.77

For the first six months of 2007, light oil and NGL revenue decreased 9% from the same period last year due to a 3% decrease in wellhead prices and a 7% decrease in production. Revenue from heavy oil decreased marginally as the increase in production was offset by a decrease in wellhead prices. Revenue from natural gas decreased 17% compared to the first six months of 2006 due to a 13% decrease in production combined with a 4% decrease in wellhead prices.

Royalties

Total royalties decreased to $21.3 million for the second quarter of 2007 from $24.0 million in 2006. Total royalties for the second quarter of 2007 were 16.7% of sales compared to 17.1% of sales for the same period in 2006. For the second quarter of 2007, royalties were 18.3% of sales for light oil, NGL and natural gas, and 15.7% for heavy oil. These rates compared to 16.7% and 17.4%, 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 six months ended June 30, 2007, royalties decreased to $41.6 million from $42.1 million for the same period last year. Total royalties for the first six months of 2007 were 16.2% of sales, compared to 15.2% of sales for the corresponding period a year ago. For the first six months of 2007, royalties were 16.8% of sales for light oil, NGL and natural gas and 15.8% for heavy oil. These rates compared to 17.2% and 13.8%, respectively, for the same period in 2006.

Operating Expenses

Operating expenses for the second quarter of 2007 increased to $30.2 million from $25.7 million in the corresponding quarter last year. Operating expenses were $10.00 per boe for the second quarter of 2007 compared to $8.51 per boe for the second quarter of 2006. For the second quarter of 2007, operating expenses were $9.40 per boe of light oil, NGL and natural gas, and $10.33 per barrel of heavy oil. The operating expenses for the same period a year ago were $8.32 and $8.64, respectively.

Operating expenses for the first six months of 2007 increased to $58.2 million from $53.5 million for the first six months in 2006. Operating expenses were $9.56 per boe for the first six months of 2007 compared to $8.63 per boe for the corresponding period of the prior year. For the first half of 2007, operating expenses were $9.23 per boe of light oil, NGL and natural gas and $9.75 per barrel of heavy oil compared to $7.93 and $9.08, respectively, for the same period a year earlier. The increase in operating expenses was primarily due to an inflationary cost environment for oilfield services and labour costs.

Transportation Expenses

Transportation expenses for the second quarter of 2007 were $8.0 million compared to $6.2 million for the second quarter of 2006. These expenses were $2.64 per boe for the second quarter of 2007 compared to $2.05 for the same period in 2006. Transportation expenses were $1.08 per boe of light oil, NGL and natural gas and $3.52 per barrel of heavy oil. The corresponding amounts for second quarter of 2006 were $0.91 and $2.74, respectively. The increase in transportation expenses for heavy oil primarily reflects longer haul distances, particularly for production at Seal, to access higher value markets.

Transportation expenses for the six months ended June 30, 2007 were $14.8 million compared to $11.9 million for the first six months of 2006. These expenses were $2.44 per boe in 2007 compared to $1.91 in 2006. Transportation expenses were $0.99 per boe of light oil, NGL and natural gas and $3.24 per barrel of heavy oil in the 2007 period, compared to $0.90 and $2.57, respectively, in the 2006 period.

General and Administrative Expenses

General and administrative expenses for the second quarter of 2007 increased to $5.5 million from $5.4 million in 2006. On a per sales unit basis, these expenses were $1.84 per boe for the second quarter of 2007 compared to $1.77 per boe for the same period in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either the second quarter of 2007 or 2006.

General and administrative expenses for the first six months of 2007 were $11.1 million, compared to $10.1 million for the prior period. On a per sales unit basis, these expenses were $1.83 per boe in 2007 and $1.63 per boe in 2006. This increase reflects a higher cost environment in the oil and gas industry, in particular as related to a tight labour market. 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 $1.9 million for the second quarter of 2007 compared to $1.8 million for the second quarter of 2006. For the six months ended June 30, 2007, compensation expense was $3.8 million compared to $3.6 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 remained consistent at $8.7 million for the second quarter of 2007 from the same period last year. 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 floating interest rates related to bank borrowings.

For the first six months of 2007, interest expense was $17.1 million compared to $17.4 million for the same period last year.

Foreign Exchange

Foreign exchange in the second quarter of 2007 was a gain of $16.5 million compared to a gain of $9.4 million in the second quarter of 2006. The gain is based on the translation of the U.S. dollar denominated long-term debt at 0.9404 at June 30, 2007 compared to 0.8674 at March 31, 2007. The 2006 gain is based on translation at 0.8969 at June 30, 2006 compared to 0.8568 at March 31, 2006.

Foreign exchange for the first six months of 2007 was a gain of $18.8 million compared to a gain of $9.2 million in the prior year. The 2007 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.9404 at June 30, 2007 compared to 0.8581 at December 31, 2006. The 2006 gain is based on translation at 0.8969 at June 30, 2006 compared to 0.8577 at December 31, 2005.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion at $42.5 million for the second quarter of 2007 represents an increase from $36.6 million for the same quarter in 2006. On a sales-unit basis, the provision for the current quarter was $14.09 per boe compared to $12.12 per boe for the same quarter in 2006. The higher rate is due to increased future development costs included in the costs subject to depletion and depreciation based on the reserves evaluation as of December 31, 2006, as well as the higher per unit cost of the acquired reserves as a result of accounting adjustments for future income taxes and asset retirement obligations.

Depletion, depreciation and accretion increased to $83.9 million for the first half of 2007 compared to $74.8 million for the same period last year. On a sales-unit basis, the provision for the current period was $13.80 per boe compared to $12.07 per boe for the same period a year earlier. The increase is attributable to the same factors influencing the second quarter calculations.

Taxes

On June 12, 2007, the federal government's bill regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received third reading, making it substantively enacted in accordance with Canadian GAAP. 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 post 2010. The majority of the Trust's temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and 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% of that trust's October 31, 2006 market capitalization for 2007, and an additional 20% of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are $730 million for 2007 and $365.0 million for each of the subsequent three years.

The provision for future income taxes for the current quarter was a recovery $11.3 million compared to a recovery of $24.7 million in the same period in 2006. For the six months ended June 30, 2007, the provision for future income taxes was a recovery of $17.8 million compared to a recovery of $31.3 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 over the value assigned to the assets.

Current tax of $1.2 million for the second quarter of 2007 is comprised entirely 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 partially offset by a $0.4 million recovery of Large Corporation Tax, reflecting the elimination of this tax during the year.

Current tax expenses were $2.7 million for the first half of 2007 compared to $4.1 million for the same period last year. The 2007 current tax expense is comprised entirely of Saskatchewan Capital Tax and Resource Surcharge. The 2006 current tax expense included $4.0 million of Saskatchewan Capital Tax and Resource Surcharge and $0.1 million of Large Corporation Tax.

Net Income

Net income for the second quarter of 2007 was $31.1 million compared to $56.2 million for the second quarter in 2006. The variance was the result of lower sales prices and higher operating costs and depletion expenses.

Net income for the first six months of 2007 was $54.8 million compared to $85.0 million for the same period in 2006. The variance was due to lower sales prices, higher operating and transportation costs, higher depletion rates and lower future tax recoveries. These negative factors were partially offset by a lower unrealized loss on financial derivatives and a higher foreign exchange gain.

Liquidity and Capital Resources

On June 26, 2007, the Trust issued 7.0 million trust units at a price of $21.35 per unit for net proceeds of $141.5 million. The proceeds were applied towards the Pembina/Lindbergh acquisition.

At June 30, 2007, total net debt was $479.0 million compared to $364.4 million at the end of 2006, with the increase mainly attributable to the bank loan incurred for the acquisition. Bank borrowings and working capital deficiency at the end of second quarter 2007 was $262.8 million compared to total credit facilities of $370 million. The syndicated loan facility was increased from $300 million to $370 million during June 2007.

Corporate Acquisition

On June 26, 2007, the Company 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. 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 the Company.

CAPITAL EXPENDITURES

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

	Three Months Ended June 30		*Six Months Ended June 30*	
($ thousands)	**2007**	2006	**2007**	2006
Land	**1,710**	2,739	**3,059**	6,049
Seismic	**360**	994	**1,369**	1,193
Drilling and completion	**17,748**	18,213	**53,177**	50,653
Equipment	**4,932**	4,765	**11,137**	13,535
Other	**878**	757	**2,095**	924
Total exploration and development	**25,628**	27,468	**70,837**	72,354
Corporate acquisition (net of working capital)	**239,884**	–	**239,884**	–
Property acquisitions	**4**	165	**35**	165
Property dispositions	**(40)**	(203)	**(308)**	(773)
Total capital expenditures	**265,476**	27,430	**310,448**	71,746

RECONCILIATION OF NET INCOME TO CASH FLOW FROM OPERATIONS

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2007**	March 31, 2007	June 30, 2006	**June 30, 2007**	June 30, 2006
Net income	**31,050**	23,783	56,162	**54,833**	85,041
Items not affecting cash:					
Unit based compensation	**1,946**	1,860	1,821	**3,806**	3,552
Amortization of deferred charges	**–**	–	200	**–**	649
Foreign exchange loss (gain)	**(16,495)**	(2,290)	(9,375)	**(18,785)**	(9,159)
Depletion, depreciation and accretion	**42,541**	41,360	36,639	**83,901**	74,806
Accretion on debentures	**34**	36	31	**70**	114
Unrealized loss on financial derivatives	**4,005**	650	7,527	**4,655**	14,144
Future income tax (recovery)	**(11,307)**	(6,508)	(24,742)	**(17,815)**	(31,334)
Non-controlling interest	**981**	760	1,202	**1,741**	1,400
Cash Flow from Operations	**52,755**	59,651	69,465	**112,406**	139,213

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.

REVIEW OF ALBERTA ROYALTY AND TAX REGIME

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007.

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 six months ended June 30, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

CONSOLIDATED BALANCE SHEETS

(thousands) (Unaudited)	**June 30, 2007**	December 31, 2006
ASSETS		
Current assets		
Accounts receivable	**$ 73,722**	$ 64,716
Crude oil inventory	**10,131**	9,609
Financial derivative contracts *(note 14)*	**806**	3,448
	84,659	77,773
Deferred charges and other assets	**–**	4,475
Petroleum and natural gas properties	**1,259,531**	959,626
Goodwill	**37,755**	37,755
	$ 1,381,945	$ 1,079,629
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 73,635**	$ 71,521
Distributions payable to unitholders	**15,016**	13,522
Bank loan	**257,977**	127,495
Financial derivative contracts *(note 14)*	**8,620**	1,055
	355,248	213,593
Long-term debt *(note 4)*	**191,355**	209,691
Convertible debentures *(note 5)*	**17,030**	18,906
Asset retirement obligations *(note 6)*	**42,951**	39,855
Deferred obligations *(note 15)*	**1,239**	2,391
Future income taxes	**166,908**	118,858
	774,731	603,294
Non-controlling interest *(note 8)*	**18,845**	17,187
UNITHOLDERS' EQUITY		
Unitholders' capital *(note 7)*	**802,902**	637,156
Conversion feature of debentures *(note 5)*	**843**	940
Contributed surplus	**15,540**	13,357
Deficit	**(230,916)**	(192,305)
	588,369	459,148
	$ 1,381,945	$ 1,079,629

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF INCOME AND COMPREHENSIVE INCOME

	Three Months Ended June 30		Six Months Ended June 30	
(thousands, except per unit data) (Unaudited)	**2007**	2006	**2007**	2006
Revenue				
Petroleum and natural gas sales	**$ 127,511**	$ 140,163	**$ 257,261**	$ 276,394
Royalties	**(21,277)**	(24,018)	**(41,601)**	(42,083)
Loss on financial derivatives *(note 14)*	**(3,914)**	(6,624)	**(4,035)**	(13,098)
	102,320	109,521	**211,625**	221,213
Expenses				
Operating	**30,188**	25,733	**58,171**	53,453
Transportation	**7,974**	6,166	**14,837**	11,860
General and administrative	**5,543**	5,356	**11,131**	10,090
Unit based compensation *(note 9)*	**1,946**	1,821	**3,806**	3,552
Interest *(note 12)*	**8,698**	8,651	**17,135**	17,437
Foreign exchange gain	**(16,495)**	(9,375)	**(18,785)**	(9,159)
Depletion, depreciation and accretion	**42,541**	36,639	**83,901**	74,806
	80,395	74,991	**170,196**	162,039
Income before taxes and non-controlling interest	**21,925**	34,530	**41,429**	59,174
Taxes (recovery) *(note 11)*				
Current	**1,201**	1,908	**2,670**	4,067
Future	**(11,307)**	(24,742)	**(17,815)**	(31,334)
	(10,106)	(22,834)	**(15,145)**	(27,267)
Income before non-controlling interest	**32,031**	57,364	**56,574**	86,441
Non-controlling interest *(note 8)*	**(981)**	(1,202)	**(1,741)**	(1,400)
Net income/Comprehensive income	**$ 31,050**	$ 56,162	**$ 54,833**	$ 85,041

CONSOLIDATED STATEMENT OF DEFICIT

Deficit, beginning of period, as previously reported	**$ (219,528)**	$ (190,745)	**$ (192,305)**	$ (181,118)
Cumulative effect of change in accounting policy *(note 2)*	**–**	–	**(10,166)**	–
Deficit, beginning of period, restated	**(219,528)**	(190,745)	**(202,471)**	(181,118)
Net Income	**31,050**	56,162	**54,833**	85,041
Distributions to unitholders	**(42,438)**	(39,297)	**(83,278)**	(77,803)
Deficit, end of period	**$ (230,916)**	$ (173,880)	**$ (230,916)**	$ (173,880)
Net income per trust unit				
Basic	**$ 0.41**	$ 0.77	**$ 0.72**	$ 1.19
Diluted	**$ 0.39**	$ 0.73	**$ 0.70**	$ 1.13
Weighted average trust units *(note 10)*				
Basic	**76,553**	72,503	**76,025**	71,589
Diluted	**82,196**	79,296	**81,850**	78,255

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		*Six Months Ended June 30*	
(thousands) (Unaudited)	**2007**	2006	**2007**	2006
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income	**$ 31,050**	$ 56,162	**$ 54,833**	$ 85,041
Items not affecting cash:				
Unit based compensation *(note 9)*	**1,946**	1,821	**3,806**	3,552
Amortization of deferred charges *(note 12)*	**–**	200	**–**	649
Foreign exchange gain	**(16,495)**	(9,375)	**(18,785)**	(9,159)
Depletion, depreciation and accretion	**42,541**	36,639	**83,901**	74,806
Accretion on debentures	**34**	31	**70**	114
Unrealized loss on financial derivatives *(note 14)*	**4,005**	7,527	**4,655**	14,144
Future income tax recovery	**(11,307)**	(24,742)	**(17,815)**	(31,334)
Non-controlling interest *(note 8)*	**981**	1,202	**1,741**	1,400
	52,755	69,465	**112,406**	139,213
Change in non-cash working capital	**956**	(15,667)	**2,303**	(14,753)
Asset retirement expenditures	**(257)**	(746)	**(960)**	(1,153)
Decrease in deferred charges and other assets	**(576)**	(489)	**(1,152)**	(978)
	52,878	52,563	**112,597**	122,329
Financing activities				
Increase in bank loan	**116,590**	16,080	**130,482**	16,599
Payments of distributions	**(34,410)**	(37,335)	**(68,235)**	(71,050)
Issue of trust units *(note 7)*	**142,992**	1,075	**145,299**	3,665
	225,172	(20,180)	**207,546**	(50,786)
Investing activities				
Petroleum and natural gas property expenditures	**(25,628)**	(27,468)	**(70,837)**	(72,354)
Acquisitions *(note 3)*	**(239,888)**	(165)	**(239,919)**	(165)
Acquisition of working capital *(note 3)*	**(13,229)**	–	**(13,229)**	–
Disposal of petroleum and natural gas properties	**40**	203	**308**	773
Change in non-cash working capital	**655**	(4,953)	**3,534**	203
	(278,050)	(32,383)	**(320,143)**	(71,543)
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		310,028
Future income taxes		(69,090)
Asset retirement obligations		(1,054)
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

	June 30, 2007	December 31, 2006
10.5% senior subordinated notes (US$247)	**$ 263**	$ 288
9.625% senior subordinated notes (US$179,699)	**191,092**	209,403
	$ 191,355	$ 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.

On June 26, 2007 the Company received an increase in its credit facilities from $300 million to $370 million.

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	(2,019)	(1,946)	(97)
Accretion	–	70	–
Balance, June 30, 2007	$ 17,600	$ 17,030	$ 843

6. ASSET RETIREMENT OBLIGATIONS

		Six Months Ended June 30, 2007		Year Ended December 31, 2006
Balance, beginning of period	$	39,855	$	33,010
Liabilities incurred		751		1,199
Liabilities acquired		1,054		–
Liabilities settled		(960)		(1,747)
Disposition of liabilities		–		(122)
Accretion		1,647		2,678
Change in estimate (1)		604		4,837
Balance, end of period	$	42,951	$	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 June 30, 2007 is $253 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		141,478
Issued on conversion of debentures	137		2,042
Issued on conversion of exchangeable shares	11		228
Issued on exercise of trust unit rights	459		3,822
Transfer from contributed surplus on exercise of trust unit rights	–		1,623
Issued pursuant to distribution reinvestment program	696		13,548
Cumulative effect of change in accounting policy *(Note 2)*	–		3,005
Balance, June 30, 2007	83,425	$	802,902

8. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price for the five day trading period ending on the record date. The exchange ratio at June 30, 2007 was 1.58968 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)	(83)
Non-controlling interest in net income	–	1,741
Balance, June 30, 2007	1,566	$ 18,845

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 $1.9 million for the three months ended June 30, 2007 ($1.8 million in 2006) and $3.8 million for the first six months in 2007 ($3.6 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:

	Six Months Ended **June 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% – 4.05%**	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	680	$ 20.62
Exercised	(459)	$ 8.33
Cancelled	(340)	$ 16.22
Balance, June 30, 2007	6,194	$ 13.98

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

The following table summarizes information about the unit rights outstanding at June 30, 2007:

Range of Exercise Prices	Number Outstanding at June 30, 2007	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at June 30, 2007	Weighted Average Exercise Price
$ 2.17 to $ 5.50	703	1.2	$ 3.25	703	$ 3.25
$ 5.51 to $ 9.00	802	2.4	$ 7.27	504	$ 7.25
$ 9.01 to $12.50	1,574	3.3	$ 11.26	439	$ 11.43
$12.51 to $16.00	522	3.5	$ 13.83	129	$ 13.80
$16.01 to $19.50	356	4.4	$ 18.78	26	$ 18.45
$19.51 to $22.97	2,237	4.4	$ 20.92	1	$ 20.72
$ 2.17 to $22.97	6,194	3.4	$ 13.98	1,802	$ 7.35

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	3,806
Transfer from contributed surplus on exercise of trust unit rights (1)	(1,623)
Balance, June 30, 2007	$ 15,540

(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	**June 30, 2007**			June 30, 2006		
	Net income	*Trust units*	*Net income per unit*	*Net income*	*Trust units*	*Net income per unit*
Net income per basic unit	**$ 31,050**	**76,553**	**$ 0.41**	$ 56,162	72,503	$ 0.77
Dilutive effect of trust unit rights	**–**	**2,022**		–	2,425	
Conversion of convertible debentures	**206**	**1,132**		662	2,088	
Exchange of exchangeable shares	**980**	**2,489**		1,202	2,280	
Net income per diluted unit	**$ 32,236**	**82,196**	**$ 0.39**	$ 58,026	79,296	$ 0.73

Six Months Ended	**June 30, 2007**			June 30, 2006		
	Net income	*Trust units*	*Net income per unit*	*Net income*	*Trust units*	*Net income per unit*
Net income per basic unit	**$ 54,833**	**76,025**	**$ 0.72**	$ 85,041	71,589	$ 1.19
Dilutive effect of trust unit rights	**–**	**2,081**		–	2,291	
Conversion of convertible debentures	**423**	**1,253**		1,758	2,088	
Exchange of exchangeable shares	**1,741**	**2,491**		1,400	2,287	
Net income per diluted unit	**$ 56,997**	**81,850**	**$ 0.70**	$ 88,199	78,255	$ 1.13

The dilutive effect of trust unit rights for the six months ended June 30, 2007 did not include 2.4 million trust unit rights (2006 – nil) 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:

	Six Months Ended June 30	
	2007	2006
Income before income taxes and non-controlling interest	**$ 41,429**	$ 59,174
Expected income taxes at the statutory rate of 34.02% (2006 – 37.00%)	**14,094**	21,893
Increase (decrease) in taxes resulting from:		
Resource allowance	**–**	(3,160)
Alberta royalty tax credit	**–**	(40)
Net income of the Trust	**(29,981)**	(26,314)
Non-taxable portion of foreign exchange gain	**(3,195)**	(1,695)
Effect of change in tax rate	**1,116**	(19,955)
Effect of change in opening tax pool balances	**(1,017)**	(1,911)
Unit based compensation	**1,295**	1,314
Other	**(127)**	(1,466)
Current taxes	**2,670**	4,067
Recovery of income taxes	**$ (15,145)**	$ (27,267)

On June 12, 2007, Bill C-52 Budget Implementation Act which contains legislative provisions to tax publicly traded income trusts in Canada received Third Reading in the Canadian House of Commons. Under Canadian accounting guidelines, a government bill is considered to be substantively enacted once it has received Third Reading in the House of Commons in the context of a minority government. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming substantively enacted under Canadian accounting guidelines, 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 June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Bank loan and miscellaneous financing	**$ 3,066**	$ 2,311	**$ 5,536**	$ 4,253
Amortization of deferred charge	**–**	200	**–**	649
Convertible debentures	**326**	1,096	**671**	1,758
Long-term debt	**5,306**	5,044	**10,928**	10,777
Total interest	**$ 8,698**	$ 8,651	**$ 17,135**	$ 17,437

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Interest paid	**$ 2,211**	$ 3,434	**$ 15,749**	$ 16,244
Income taxes paid	**$ 3,347**	$ 1,917	**$ 4,986**	$ 3,538

14. FINANCIAL DERIVATIVE CONTRACTS

At June 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

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 June 30		*Six Months Ended June 30*	
	2007	2006	**2007**	2006
Realized gain on financial derivatives	**$ 91**	$ 903	**$ 620**	$ 1,046
Unrealized loss on financial derivatives	**(4,005)**	(7,527)	**(4,655)**	(14,144)
	$ (3,914)	$ (6,624)	**$ (4,035)**	$ (13,098)

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 June 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

Subsequent to June 30, 2007, the Trust added the following derivative contracts:

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

At June 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*
Operating leases	$ 6,383	$ 2,120	$ 2,349	$ 1,900	$ 14
Transportation agreements	2,532	1,758	661	92	21
Total	$ 8,915	$ 3,878	$ 3,010	$ 1,992	$ 35

OTHER

At June 30, 2007, there were outstanding letters of credit aggregating $7.4 million (June 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 June 30, 2007 was $3.6 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 June 30, 2007, 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.

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
Secretary
Partner
Burnet, Duckworth & Palmer LLP

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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