BAYTEX

ENERGY TRUST

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BAYTEX ENERGY TRUST ANNOUNCES FISCAL 2005 RESULTS

Baytex Energy Trust (TSX-BTE.UN) is pleased to announce its operating and financial results for the three months and year ended December 31, 2005.

2005 Highlights

- established multi-year, low-cost development inventory at Seal for heavy oil and at Stoddart for natural gas;
- acquired complementary heavy oil assets at Celtic at excellent purchase metrics and added numerous development opportunities;
- completed a $100 million convertible debentures financing which significantly enhanced Baytex's financial flexibility;
- increased cash flow from operations by 56% to $3.38 per trust unit;
- maintained monthly distributions at $0.15 per trust unit while reducing payout ratio to 50% from 83% in 2004;
- achieved FD&A costs of $4.69 per boe and capital investment recycle ratio of 4.7;
- replaced production by 260%;
- grew reserves per trust unit by 13% to 1.96 boe;
- improved reserve life index by 21% to 11.0 years; and
- enhanced net asset value per trust unit by 103% to $19.96.

	Three Months Ended			Years Ended	
FINANCIAL	**December 31, 2005**	September 30, 2005	December 31, 2004	**December 31, 2005**	December 31, 2004
($ thousands, except per unit amounts)					
Petroleum and natural gas sales	**162,356**	154,930	111,521	**546,940**	420,400
Cash flow from operations (1)	**65,487**	67,501	28,114	**227,465**	136,012
Per unit - basic	**0.95**	1.00	0.44	**3.38**	2.17
- diluted	**0.86**	0.90	0.42	**3.12**	2.07
Cash distributions	**28,582**	27,495	28,856	**114,221**	113,063
Per unit	**0.45**	0.45	0.45	**1.80**	1.80
Net income	**35,184**	39,542	42,696	**79,876**	16,764
Per unit - basic	**0.51**	0.59	0.67	**1.19**	0.27
- diluted	**0.47**	0.54	0.64	**1.13**	0.26
Exploration and development	**31,046**	39,395	29,023	**130,492**	94,483
Net acquisitions (dispositions)	**(47,477)**	68,678	75,423	**21,957**	186,183
Total capital expenditures	**(16,431)**	108,073	104,446	**152,449**	280,666
Long-term notes	**209,799**	208,935	216,583	**209,799**	216,583
Convertible debentures	**73,766**	82,695	-	**73,766**	-
Bank loan	**123,588**	188,441	161,444	**123,588**	161,444
Other working capital deficiency	**16,506**	5,482	34,504	**16,506**	34,504
Notional mark-to-market liabilities (assets)	**(5,183)**	21,226	9,513	**(5,183)**	9,513
Total net debt	**418,476**	506,779	422,044	**418,476**	422,044

OPERATING	Three Months Ended **December 31, 2005**	Three Months Ended September 30, 2005	Three Months Ended December 31, 2004	Years Ended **December 31, 2005**	Years Ended December 31, 2004
Daily production					
Light oil & NGL (bbl/d)	**4,022**	4,063	2,786	**3,842**	2,172
Heavy oil (bbl/d)	**24,051**	20,061	22,490	**21,265**	22,703
Total oil (bbl/d)	**28,073**	24,124	25,276	**25,107**	24,875
Natural gas (mmcf/d)	**58.9**	63.9	55.5	**60.4**	54.9
Oil equivalent (boe/d @ 6:1)	**37,895**	34,780	34,525	**35,177**	34,022
Average prices (before hedging)					
WTI oil (US$/bbl)	**60.02**	63.19	48.28	**56.56**	41.40
Edmonton par oil ($/bbl)	**71.18**	76.51	57.72	**68.75**	52.57
BTE light oil & NGL ($/bbl)	**55.78**	59.24	50.46	**53.84**	48.64
BTE heavy oil ($/bbl)	**37.75**	45.39	31.24	**37.38**	30.32
BTE total oil ($/bbl)	**40.33**	47.74	33.35	**39.90**	31.91
BTE natural gas ($/mcf)	**10.69**	8.39	6.60	**8.22**	6.46
BTE oil equivalent ($/boe)	**46.48**	48.54	35.03	**42.60**	33.75
TRUST UNIT INFORMATION					
Unit Price					
High	**$18.78**	$18.60	$14.00	**$18.78**	$14.00
Low	**$14.13**	$13.45	$12.60	**$12.42**	$ 9.78
Close	**$17.70**	$18.55	$12.77	**$17.70**	$12.77
Units traded (thousands)	**21,534**	22,134	22,796	**87,481**	93,253
Units outstanding (thousands)[2]	**71,475**	70,524	68,817	**71,475**	68,817
Foreign ownership	**33%**	30%	31%	**33%**	31%

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

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

Operations Review

Capital expenditures during 2005 totalled $152 million, with $130 million spent on exploration and development activities and $22 million spent on acquisitions net of dispositions of assets.

During the fourth quarter, Baytex participated in the drilling of 11 (7.2 net) wells, resulting in one (1.0 net) oil well and 10 (6.2 net) gas wells for a 100% success rate. In addition, seven wells were drilled by other operators with Baytex retaining various working or royalty interests. For all of 2005, Baytex participated in the drilling of 118 (107.3 net) wells, resulting in 64 (60.4 net) oil wells, 41 (34.4 net) gas wells, four (4.0 net) stratigraphic test wells and nine (8.5 net) dry holes. Overall success rate for the year was 92.4% (92.1% net).

The benefits of this capital program will be realized for years to come. At Stoddart, a total of nine wells were drilled during the year, resulting in eight successful natural gas wells with high yields of NGL. Production from this area has grown to over 4,500 boe/d from the 3,300 boe/d at the time of acquisition in December 2004. Approximately 40 future drilling locations have been identified in this area, and six of these locations are planned to be drilled in 2006 to help sustain natural gas and NGL production. Baytex will continue to grow Stoddart through land purchases and seismic activities commensurate with increasing knowledge of this area.

At Seal, six horizontal wells drilled in the 2004/05 winter are currently producing approximately 500 bbl/d. Two horizontal wells and three vertical stratigraphic test wells have been drilled this winter to further delineate this land block on which Baytex has identified in excess of 100 development locations. Owing to a lack of production infrastructure, current production is being sold at a large discount to market prices received in areas with more developed infrastructure. Baytex is currently working on improving marketing arrangements before embarking on a large-scale development program. Baytex is very excited about the vast potential for development on its 100 sections of land in this area, and is certain that Seal will anchor its heavy oil production needs for the coming years.

In September 2005, Baytex purchased 3,500 boe/d of mainly heavy oil production at Celtic for $69 million. An unsolicited offer in December resulted in the sale of the lower-netback SAGD production just acquired for $45.3 million. These assets had been budgeted by Baytex to produce an average of 1,900 bbl/d of heavy oil for 2006 and were estimated by Baytex to have 1.8 million barrels of proved reserves and 2.1 million barrels of proved plus probable reserves as at year-end 2005. The decision to acquire the Celtic assets was based on the primary (cold) development opportunities which have been retained by Baytex. Production from the retained assets has grown to a current rate of over 3,000 boe/d from the original 1,750 boe/d at the time of acquisition. An active capital program has been planned for this area in 2006, including the drilling of 30 wells. This acquisition complements existing operations in the core area of Tangleflags and provides numerous low cost development opportunities.

Financial Review

Oil and gas production during 2005 averaged 35,177 boe/d, an increase of 3% over the prior year. Combined with a 25% increase in average wellhead oil price and a 27% increase in average wellhead gas price, cash flow from operations for the year set a record of $227 million, representing an increase of 67% over that of 2004.

The rapid ascent of oil prices from an average of US$31.04 for WTI crude in 2003 to US$56.56 in 2005 caused Baytex to incur significant losses from its hedging program. Losses from WTI derivative contracts in 2005, although an improvement over the $82 million incurred in 2004, totalled $48 million. With the expiry of these low price contracts at the end of 2005, Baytex looks forward to reporting financial results in 2006 that, for the first time since its inception as an income trust, reflect the true cash flow capacity of its production base.

During the year, Baytex maintained its monthly distributions at $0.15 per unit. Despite the significant hedging losses incurred, payout ratio in 2005 improved to 50% from 83% one year ago. The low payout ratio in 2005 brought the cumulative payout ratio since inception to the end of 2005 to a more sustainable 65%.

Total debt at year-end 2005 was $418 million, including $74 million of convertible debentures issued in June 2005 with a conversion price of $14.75 per trust unit. As of the end of February 2006, a total of $45 million of the original issue of $100 million of these debentures have been tendered for conversion. The majority of Baytex's remaining debt is in the form of US$ denominated senior subordinated term notes maturing in 2010. Baytex has excellent financial flexibility as outstanding revolving bank debt amounts to less than half a year of current cash flow.

Capital Program Efficiency

Baytex's internal development program, led by drilling at Stoddart and Seal, was an unequivocal success. Total expenditures incurred of $130 million, though relatively modest at 57% of cash flow from operations, replaced 128% of production during the year. This outstanding program was augmented by an excellent acquisition at Celtic, which added 16.5 million boe of heavy oil and natural gas reserves at a price net of dispositions of $1.33 per boe. Overall finding, development and acquisition ("FD&A") costs of $4.69 per boe excluding future development capital ("FDC") and capital investment recycle ratio of 4.7 should place Baytex amongst the best in our industry in 2005. More impressively, Baytex replaced production by 260%, increased reserves per trust unit by 13% and improved reserve life index by 21%, all by spending only two-thirds of its cash flow.

The efficiency of Baytex's 2005 capital program is summarized as follows:

	Proved Reserves	Proved + Probable Reserves
FD&A Costs (excluding FDC) ($/boe)		
Exploration and Development	8.94	8.16
Acquisition (net of disposal)	1.48	1.33
Total	5.19	4.69
FD&A Costs (including FDC) ($/boe)		
Exploration and Development	13.50	12.38
Acquisition (net of disposal)	3.46	3.13
Total	8.45	7.69
Operating Netback ($/boe)	22.08	22.08
Recycle Ratio		
Excluding FDC	4.3	4.7
Including FDC	2.6	2.9
Reserves Replacement Ratio	235%	260%

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2005 year-end report.

	Discounted at 10%	
	Forecast Prices	Constant Prices
Proved plus probable reserves (1)	$1,784,668,000	$1,932,625,000
Undeveloped land (2)	96,145,000	96,145,000
Net debt (3)	(349,893,000)	(349,893,000)
Net asset value	$1,530,920,000	$1,678,877,000
Total trust units outstanding (4)	76,705,151	76,705,151
Net asset value per trust unit	$19.96	$21.89

Notes:

(1) As evaluated by Sproule Associates Limited as at December 31, 2005. Net present value of future net revenue does not represent fair market value of the reserves.
(2) As evaluated by Baytex as at December 31, 2005 on 740,000 net acres of undeveloped land.
(3) Long-term debt net of working capital as at December 31, 2005, excluding convertible debentures and $5.2 million of notional assets associated with the mark-to-market value of derivative contracts.
(4) Includes 69,283,369 trust units, 1,597,028 exchangeable shares converted at an exchange ratio of 1.37201 and 5,230,644 trust units issuable on the conversion of the $73.8 million outstanding convertible debentures as at December 31, 2005.

Oil and Gas Reserves

Baytex announced certain of its year-end 2005 reserves information on February 15, 2006. Following is additional summary information with regard to oil and gas reserves as at December 31, 2005. Other detailed information as required under NI 51-101 will be included in Baytex's Annual Information Form.

Reconciliation of Company Interest Reserves[3]
By Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Oil		
Factors	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved + Probable [1] (Mbbl)	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved + Probable [1] (Mbbl)
December 31, 2004	6,386	2,431	8,817	55,874	24,887	80,761
Extensions	340	43	383	7,009	3,498	10,507
Discoveries	19	12	31	426	175	601
Technical Revisions	(505)	(183)	(688)	520	(4,148)	(3,628)
Acquisitions	-	-	-	15,777	1,776	17,553
Dispositions	-	-	-	(1,800)	(300)	(2,100)
Economic Factors	102	39	141	894	398	1,292
Production	(870)	-	(870)	(7,434)	-	(7,434)
December 31, 2005	5,472	2,342	7,814	71,266	26,286	97,552

	Natural Gas Liquids			Natural Gas		
Factors	Proved [1] (Mbbl)	Probable [1] (Mbbl)	Proved+ Probable [1] (Mbbl)	Proved [1] (MMcf)	Probable [1] (MMcf)	Proved + Probable [1] (MMcf)
December 31, 2004	3,672	590	4,262	110,999	44,101	155,100
Extensions	1,113	664	1,777	19,691	8,315	28,006
Discoveries	149	17	166	1,636	213	1,849
Technical Revisions	(825)	(26)	(851)	8,631	(3,770)	4,861
Acquisitions	-	-	-	4,856	1,297	6,153
Dispositions	-	-	-	-	-	-
Economic Factors	59	9	68	1,776	706	2,482
Production	(533)	-	(533)	(22,052)	-	(22,052)
December 31, 2005	3,635	1,254	4,889	125,537	50,862	176,399

	Oil Equivalent [2]		
Factors	Proved [1] (MBoe)	Probable [1] (MBoe)	Proved+ Probable [1] (MBoe)
December 31, 2004	84,432	35,258	119,690
Extensions	11,744	5,591	17,335
Discoveries	867	240	1,107
Technical Revisions	629	(4,985)	(4,356)
Acquisitions	16,586	1,992	18,578
Dispositions	(1,800)	(300)	(2,100)
Economic Factors	1,351	564	1,915
Production	(12,512)	-	(12,512)
December 31, 2005	101,297	38,360	139,657

Notes:

(1) Reserves information as at December 31, 2004 and 2005 is prepared in accordance with NI 51-101.
(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(3) Company interest reserves include solution gas but do not include royalty interest.

Management's Discussion and Analysis

Management's discussion and analysis ("MD&A"), dated March 8, 2006, should be read in conjunction with the unaudited interim consolidated financial statements for the three months and the year ended December 31, 2005 and the audited consolidated financial statements and MD&A for the year ended December 31, 2004. Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

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

Production. Light oil and NGL production for the fourth quarter of 2005 increased by 44% to 4,022 bbl/d from 2,786 bbl/d a year earlier. Heavy oil production increased 7% to 24,051 bbl/d for the fourth quarter of 2005 compared to 22,490 bbl/d a year ago. Natural gas production increased by 6% to 58.9 mmcf/d for the fourth quarter of 2005 compared to 55.5 mmcf/d for the same period last year. The increase in light oil, NGL and natural gas production is due to the acquisitions completed in 2004 and the subsequent development of these assets. The increase in heavy oil production is attributable to the Celtic acquisition made during the year.

For the year ended December 31, 2005, light oil & NGL production increased by 76% to 3,842 bbl/d from 2,172 bbl/d for last year. Heavy oil production for 2005 was down 7% to 21,265 bbl/d compared to 22,703 bbl/d in 2004. Natural gas production increased by 10% to average 60.4 mmcf/d for 2005 compared to 54.9 mmcf/d for 2004. The reasons for the increase in production for light oil and NGL and natural gas are as discussed in the quarterly comparisons. The decrease in heavy oil production is due to the reduction in drilling, where 60 net heavy oil wells were drilled in 2005 compared to 95 net wells drilled in 2004.

Revenue. Petroleum and natural gas sales increased 46% to $162.4 million for the fourth quarter of 2005 from $111.5 million for the same period in 2004**.** For the year, petroleum and natural gas sales increased by 30% to $546.9 million in 2005 from $420.4 million a year earlier.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2005 were 70 barrels per day higher (three months ended December 31, 2004 – 63 barrels per day higher) than the production for the period due to inventory in transit under the Frontier supply agreement. The inventory fluctuation had minimal effect for the years ended December 31, 2005 and December 31, 2004.

	Three Months ended December 31			
	2005		2004	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**20,637**	**55.78**	12,931	50.46
Heavy oil	**83,783**	**37.75**	64,881	31.24
Derivative contracts loss	**(14,109)**	**(6.36)**	(27,570)	(11.83)
Total oil revenue	**90,311**	**34.88**	50,242	21.55
Natural gas revenue (mcf)	**57,936**	**10.69**	33,709	6.60
Total revenue (boe @ 6:1)	**148,247**	**42.44**	83,951	26.38

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

Revenue from light oil and NGL for the fourth quarter of 2005 increased 60% from the same period a year ago due to a 44% increase in production and a 11% increase in wellhead prices. Revenue from heavy oil increased 29% due to a 7% increase in production and a 21% increase in wellhead prices. Revenue from natural gas increased 72% as the result of a 62% increase in wellhead prices and a 6% increase in production.

	Year ended December 31			
	2005		2004	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue (barrels)				
Light oil & NGL	**75,507**	**53.84**	38,673	48.64
Heavy oil	**290,163**	**37.38**	252,016	30.32
Derivative contracts loss	**(48,462)**	**(6.24)**	(78,124)	(8.58)
Total oil revenue	**317,208**	**34.61**	212,565	23.34
Natural gas revenue (mcf)	**181,270**	**8.22**	129,711	6.46
Total revenue (boe @ 6:1)	**498,478**	**38.82**	342,276	27.48

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

For the year ended December 31, 2005, light oil and NGL revenue increased 95% from the same period last year due to an 11% increase in wellhead prices and a 76% increase in production. Revenue from heavy oil increased 15% due to a 23% increase in wellhead prices partially offset by a 7% decrease in production. Revenue from natural gas increased 40% compared to 2004, as production increased 10% combined with a price increase of 27%.

Royalties. Total royalties increased to $27.3 million for the fourth quarter of 2005 from $17.4 million in 2004. This increase is reflective of the increase in total revenue. Total royalties for the fourth quarter of 2005 were 16.8% of sales compared to 15.6% of sales for the same period in 2004. For the fourth quarter of 2005, royalties were 16.2% of sales for light oil and NGL, 11.7% for heavy oil and 24.3% for natural gas. These rates compared to 15.9%, 13.5% and 19.5%, respectively, for the same period last year.

For the year ended December 31, 2005, royalties increased to $81.9 million from $66.0 million for last year. Total royalties in 2005 were 15.0% of sales, compared to 15.7% of sales for 2004. For 2005, royalties were 15.1% of sales for light oil and NGL, 12.4% for heavy oil and 19.0% for natural gas. These rates compared to 14.1%, 13.3% and 20.9%, respectively, for 2004. The royalty rate for natural gas was lower in 2005 due to a retroactive adjustment in the gas cost allowance used in the calculation of royalties.

Operating Expenses. Operating expenses for the fourth quarter of 2005 increased to $33.3 million from $24.3 million in the corresponding quarter last year. Operating expenses were $9.55 per boe for the fourth quarter of 2005 compared to $7.63 per boe for the fourth quarter of 2004. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services, and the addition of heavy oil production utilizing SAGD technology which was disposed of at year-end 2005. For the fourth quarter of 2005, operating expenses were $6.28 per barrel of light oil and NGL, $11.00 per barrel of heavy oil and $1.22 per mcf of natural gas. The operating expenses for the same period a year ago were $8.57, $8.61 and $0.83, respectively.

Operating expenses for the year 2005 increased to $110.6 million from $89.1 million in 2004. Operating expenses were $8.62 per boe for 2005 compared to $7.15 per boe for the prior year. In 2005, operating expenses were $9.06 per barrel of light oil and NGL, $9.56 per barrel of heavy oil and $1.08 per mcf of natural gas versus $9.51, $7.83 and $0.82, respectively, for the same period a year earlier.

Transportation Expenses. Transportation expenses for the fourth quarter of 2005 were $6.0 million compared to $4.6 million for the fourth quarter of 2004. These expenses were $1.71 per boe for the fourth quarter of 2005 compared to $1.43 for the same period in 2004. Transportation expenses were $2.02 per barrel of oil and $0.14 per mcf of natural gas. The corresponding amounts for 2004 were $1.58 and $0.17, respectively.

Transportation expenses for the year ended December 31, 2005 were $22.4 million compared to $18.7 million for 2004. These expenses were $1.74 per boe in 2005 compared to $1.50 in 2004. Transportation expenses were $2.11 per barrel of oil and $0.14 per mcf of natural gas in 2005, and $1.66 per barrel of oil and $0.18 per mcf of natural gas in 2004.

General and Administrative Expenses. General and administrative expenses for the fourth quarter of 2005 increased slightly to $4.6 million from $4.1 million in 2004. On a per sales unit basis, these expenses were $1.32 per boe for the fourth quarter of 2005 compared to $1.28 per boe for the same period in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either the fourth quarter of 2005 or 2004.

General and administrative expenses for the year were $16.0 million, compared to $15.2 million for the prior year. On a per sales unit basis, these expenses were $1.25 per boe in 2005 and $1.22 per boe in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either 2005 or 2004.

Unit-based Compensation Expense. Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2005 compared to $1.0 million for the fourth quarter of 2004. For the year ended December 31, 2005, compensation expense was $5.3 million compared to $4.6 million for 2004.

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.

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

Interest Expenses. Interest expense increased to $9.7 million for the fourth quarter of 2005 from $6.4 million for the same quarter last year, primarily due to the increased debt used to finance acquisitions completed in 2004, plus a gradual increase in interest rates.

In 2005, interest expense was $33.1 million compared to $19.4 million for last year. The increase is attributable to the same factors influencing the fourth quarter variance.

Foreign Exchange. Foreign exchange in the fourth quarter of 2005 was a loss of $0.9 million compared to a gain of $10.9 million in the prior year. The loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8613 at September 30, 2005. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7912 at September 30, 2004.

The foreign exchange gain for 2005 was $6.8 million compared to $16.0 million in the prior year. The 2005 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8308 at December 31, 2004. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003.

Depletion, Depreciation and Accretion. The provision for depletion, depreciation and accretion at $41.6 million for the fourth quarter of 2005 is almost unchanged from the same quarter a year ago despite higher production, due to a lower depletion rate resulting from low-cost proved reserves added from the Celtic acquisition. On a sales-unit basis, the provision for the current quarter was $11.91 per boe compared to $13.04 per boe for the same quarter in 2004.

Depletion, depreciation and accretion increased to $167.1 million for 2005 compared to $160.8 million for last year. On a sales-unit basis, the provision for the current year was $13.02 per boe compared to $12.91 per boe for 2004.

Income Taxes. Current tax expenses increased to $2.4 million for the fourth quarter of 2005 from $1.9 million for the same quarter a year ago. The current tax expense is comprised of $2.1 million of Saskatchewan Capital Tax and $0.3 million of Large Corporation Tax compared to $1.6 million and $0.3 million, respectively, in the corresponding period in 2004.

Current tax expenses were $8.7 million for 2005 compared to $9.0 million last year. The current tax expense is comprised of $6.9 million of Saskatchewan Capital Tax and $1.8 million of Large Corporation Tax compared to $7.0 million and $2.0 million, respectively, in 2004.

Net Income. Net income for the fourth quarter of 2005 was $35.2 million compared to $42.7 million for the fourth quarter in 2004. The variance was the result of higher production and higher sales prices, which was more than offset by foreign exchange losses and an increase in future tax provision.

Net income for 2005 was $79.9 million compared to $16.8 million for 2004. The variance was primarily due to higher production, higher sales prices and lower loss in financial derivatives for 2005.

Liquidity and Capital Resources. 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 net proceeds were used to reduce outstanding bank indebtedness.

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 as at the date of issue. Issue costs are amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. As at December 31, 2005, $22.8 million principal amount of debentures had been tendered for conversion into trust units.

At December 31, 2005, total net debt excluding notional mark-to-market assets or liabilities was $423.7 million compared to $412.5 million at the end of 2004.

Capital Expenditures.

The Trust's total capital expenditures for 2005 and 2004 are summarized as follows:

	Year Ended December 31	
($ thousands)	**2005**	2004
Land	**7,126**	8,744
Seismic	**4,949**	1,283
Drilling and completion	**90,180**	55,322
Equipment	**23,611**	25,982
Other	**4,626**	3,152
Total exploration and development	**130,492**	94,483
Corporate acquisition	**-**	111,042
Property acquisitions	**70,986**	89,582
Property dispositions	**(49,029)**	(14,441)
Net capital expenditures	**152,449**	280,666

Evaluation of 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. For the year ended December 31, 2005, the Disclosure Officers evaluated the effectiveness of the disclosure controls and procedures. As a result of this evaluation, the Disclosure Officers have concluded that the disclosure controls and procedures are effective to provide reasonable assurance that all material or potentially material information about the activities of the Trust is made known to them by others within Baytex.

It should be noted that while our President and Chief Executive Officer and Chief Financial Officer believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance that they are effective, 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, not absolute, assurance that the objectives of the control system are met.

Conference Call

Baytex will host a conference call and question and answer session at 2:00 p.m. MT (4:00 p.m. ET) on Wednesday, March 8, 2006 to discuss our fourth quarter results. The conference call will be hosted by Raymond Chan, President and Chief Executive Officer, Derek Aylesworth, Chief Financial Officer and Anthony Marino, Chief Operating Officer. Interested parties are invited to participate by calling toll-free across North America at 1-800-741-0104. An archived recording of the call will be available from March 8, 2006 until March 22, 2006 by dialing 1-800-558-5253 or 416-626-4100 within the Toronto area, and entering the reservation number 21283532. The conference call will also be archived on Baytex's website at www.baytex.ab.ca.

Forward-Looking Statements

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to Management's approach to operations and Baytex's production, cash flow, debt levels and cash distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in Baytex's areas of operations; and other factors, many of which are beyond the control of Baytex. 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.

Baytex Energy Trust is a conventional oil and gas income trust focused on maintaining its production and asset base through internal property development and delivering consistent returns to its unitholders. Trust units of Baytex are traded on the Toronto Stock Exchange under the symbol BTE.UN.

Financial statements for the years ended December 31, 2005 and December 31, 2004 are attached.

For further information, please contact:

Baytex Energy Trust
Ray Chan, President & Chief Executive Officer
Telephone: (403) 267-0715
or
Derek Aylesworth, Chief Financial Officer
Telephone: (403) 538-3639
or
Kathy Robertson, Investor Relations Representative
Telephone: (403) 538-3645
Toll Free Number: 1-800-524-5521
Website: www.baytex.ab.ca

Baytex Energy Trust
Consolidated Balance Sheets
(thousands) (Unaudited)

	December 31, 2005	December 31, 2004 (restated - note 3)
Assets		
Current assets		
Accounts receivable	$ 73,869	$ 41,154
Crude oil inventory	9,984	7,299
Financial derivative contracts (note 13)	5,183	-
	89,036	48,453
Deferred charges and other assets	9,038	6,491
Petroleum and natural gas properties	969,738	1,009,933
Goodwill (note 4)	37,755	39,259
	$ 1,105,567	$ 1,104,136
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 89,966	$ 72,976
Distributions payable to unitholders	10,393	9,981
Bank loan	123,588	161,444
Financial derivative contracts (note 13)	-	9,513
	223,947	253,914
Long-term debt (note 5)	209,799	216,583
Convertible debentures (note 6)	73,766	-
Asset retirement obligations (note 7)	33,010	73,297
Deferred obligations (note 14)	4,558	-
Future income taxes	159,745	164,909
	704,825	708,703
Non-controlling interest (note 9)	12,810	12,936
Unitholders' Equity		
Unitholders' capital (note 8)	555,020	515,663
Conversion feature of debentures (note 6)	3,698	-
Contributed surplus	10,332	6,287
Accumulated distributions	(267,986)	(146,445)
Accumulated income	86,868	6,992
	387,932	382,497
	$ 1,105,567	$ 1,104,136

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Operations and Accumulated Income (Deficit)
(thousands, except per unit data) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2005	2004	**2005**	2004
Revenue		(restated - note 3)		(restated - note 3)
Petroleum and natural gas sales	**$ 162,356**	$ 111,521	**$ 546,940**	$ 420,400
Royalties	**(27,269)**	(17,392)	**(81,898)**	(65,988)
Realized loss on financial derivatives	**(14,109)**	(27,570)	**(48,462)**	(78,124)
Unrealized gain on financial derivatives	**26,409**	40,585	**14,696**	597
	147,387	107,144	**431,276**	276,885
Expenses				
Operating	**33,344**	24,293	**110,648**	89,078
Transportation	**5,959**	4,550	**22,399**	18,714
General and administrative	**4,617**	4,069	**16,010**	15,243
Unit-based compensation (note 10)	**1,809**	983	**5,346**	4,646
Interest (note 11)	**9,740**	6,448	**33,124**	19,412
Foreign exchange loss (gain)	**864**	(10,851)	**(6,784)**	(15,979)
Depletion, depreciation and accretion	**41,587**	41,517	**167,135**	160,808
	97,920	71,009	**347,878**	291,922
Income (loss) before income taxes and non-controlling interest	**49,467**	36,135	**83,398**	(15,037)
Income taxes				
Current expense	**2,410**	1,850	**8,747**	9,000
Future expense (recovery)	**11,088**	(9,621)	**(7,074)**	(41,237)
	13,498	(7,771)	**1,673**	(32,237)
Income before non-controlling interest	**35,969**	43,906	**81,725**	17,200
Non-controlling interest (notes 3 and 9)	**(785)**	(1,210)	**(1,849)**	(436)
Net income	**35,184**	42,696	**79,876**	16,764
Accumulated income (deficit), beginning of period, as previously reported	**45,898**	(36,415)	**5,694**	(8,069)
Accounting policy change unit based compensation (note 3)	**5,786**	711	**1,298**	(1,703)
Accumulated income (deficit), beginning of period, as restated	**51,684**	(35,704)	**6,992**	(9,772)
Accumulated income, end of period	**$ 86,868**	$ 6,992	**$ 86,868**	$ 6,992
Net income per trust unit				
Basic	**$ 0.51**	$ 0.67	**$ 1.19**	$ 0.27
Diluted	**$ 0.47**	$ 0.65	**$ 1.13**	$ 0.26
Weighted average trust units				
Basic	**68,669**	63,385	**67,382**	62,574
Diluted	**77,610**	66,344	**74,131**	65,682

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
(thousands) (Unaudited)

	Three Months Ended December 31		Year Ended December 31	
	2005	2004 (restated - note 3)	**2005**	2004 (restated - note 3)
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net income (loss)	**$ 35,184**	$ 42,696	**$ 79,876**	$ 16,764
Items not affecting cash:				
Unit-based compensation (note 10)	**1,809**	983	**5,346**	4,646
Amortization of deferred charges	**459**	2,795	**1,492**	11,171
Unrealized foreign exchange gain	**864**	(10,851)	**(6,784)**	(15,979)
Depletion, depreciation and accretion	**41,587**	41,517	**167,135**	160,808
Accretion on debentures	**120**	-	**321**	-
Unrealized gain on financial derivatives (note 13)	**(26,409)**	(40,585)	**(14,696)**	(597)
Future income tax (recovery)	**11,088**	(9,621)	**(7,074)**	(41,237)
Non-controlling interest (note 9)	**785**	1,210	**1,849**	436
	65,487	28,144	**227,465**	136,012
Change in non-cash working capital	**3,393**	5,342	**(20,212)**	3,589
Asset retirement expenditures	**(382)**	(1,189)	**(1,637)**	(2,739)
Decrease in deferred charges and other assets	**(1,134)**	53	**(977)**	212
	67,364	32,350	**204,639**	137,074
FINANCING ACTIVITIES				
Issuance of convertible debentures (note 6)	**-**	-	**100,000**	-
Convertible debentures issue costs (note 6)	**-**	-	**(4,250)**	-
Increase (Decrease) in bank loan	**(64,853)**	47,601	**(37,856)**	161,444
Payments of distributions	**(30,847)**	(28,169)	**(121,129)**	(112,074)
Issue of trust units	**3,457**	44,295	**9,824**	44,505
	(92,243)	63,727	**(53,411)**	93,875
INVESTING ACTIVITIES				
Petroleum and natural gas property expenditures	**(29,608)**	(118,605)	**(201,478)**	(184,065)
Corporate acquisitions	**-**	-	**-**	(111,042)
Proceeds on disposal of petroleum and natural gas properties	**46,039**	14,159	**49,029**	14,441
Change in non-cash working capital	**8,448**	6,586	**1,221**	(4,014)
	24,879	(97,860)	**(151,228)**	(284,680)
Change in cash and short-term investments	**-**	(1,783)	**-**	(53,731)
Cash and short-term investments, beginning of period	**-**	1,783	**-**	53,731
Cash and short-term investments, end of period	**$ -**	$ -	**$ -**	$ -

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements
Three Months and Year Ended December 31, 2005 and 2004
(all tabular amounts in thousands, except per unit amounts) (unaudited)

1. Basis of Presentation

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

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

2. Accounting Policies

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2004, except as described in note 3. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes thereto for the year ended December 31, 2004.

3. Change in Accounting Policy

Unit based Compensation

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

As a result of retroactively adopting the fair value method of estimating compensation expense, net income for the comparative year ended December 31, 2004 was increased by $3.0 million, net of non-controlling interest of $0.09 million. The opening 2004 accumulated deficit was decreased by $1.7 million, net of non-controlling interest of $0.1 million. There was also a decrease in unitholders' capital of $0.07 million during 2004 relating to the transfer of value from contributed surplus on exercise of unit option rights. There was no impact on cash flow as a result of adopting this policy.

4. Corporate Acquisition

The Company has finalized its purchase allocation related to the acquisition made in 2004.Goodwill of $37.8 million was determined based on the excess of the total consideration paid less the fair value assigned to the identifiable assets and liabilities including the future income tax liability.

5. Long-term Debt

	December 31, 2005	December 31, 2004
10.5% senior subordinated notes (US$247)	**$ 288**	$ 297
9.625% senior subordinated notes (US$179,699)	**209,511**	216,286
	$ 209,799	$ 216,583

6. Convertible Unsecured Subordinated Debentures

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

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

Maturity date	December 31, 2010
Interest rate	6.5%
Conversion price per trust unit	$14.75

Debentures issued on June 6, 2005	$	100,000
Fair value of conversion feature		(4,800)
Conversion of Debentures and amortization of discount		(21,434)
Debentures outstanding December 31, 2005	$	73,766

7. Asset Retirement Obligations

	Year Ended December 31			
	2005		2004	
Balance, beginning of period	**$**	**73,297**	$	55,996
Liabilities incurred		**406**		4,623
Liabilities settled		**(1,637)**		(2,739)
Acquisition of liabilities		**3,410**		12,797
Disposition of liabilities		**(2,117)**		(1,722)
Accretion		**5,762**		4,342
Change in estimate(1)		**(46,111)**		-
Balance, end of period	**$**	**33,010**	$	73,297

(1) The change in estimate is primarily due to the significant increase in recent and forecasted market price of petroleum and natural gas. Consequentially, the projected economic life of the wells and facilities are extended, resulting in wells and facilities being abandoned and reclaimed further out in the future and thus a lower present value of asset retirement obligations.

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 December 31, 2005 is $218 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 2.5 percent for the years 2006 to 2008, and 1.5 percent thereafter.

8. Unitholders' Capital

Trust Units

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

	Number of units	Amount
Balance December 31, 2003	60,821	$ 449,403
Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights (1) (restated – note 3)	113	1,407
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	515,663
Issued on conversion of Debentures	1,549	22,859
Issued on conversion of Exchangeable Shares	363	5,373
Issued on exercise of trust unit rights (1)	369	4,217
Issued pursuant to distribution reinvestment program	464	6,908
Balance December 31, 2005	69,283	$ 555,020

(1) Includes compensation expense transferred from contributed surplus.

9. 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 December 31, 2005 was 1.37201 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.

Non-controlling Interest	Number of Exchangeable Shares	Amount
Balance December 31, 2003 (restated – note 3)	3,725	$ 25,590
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income	-	436
Balance December 31, 2004 (restated – note 3)	1,876	12,936
Exchanged for trust units	(279)	(1,975)
Non-controlling interest in net income	-	1,849
Balance December 31, 2005	1,597	$ 12,810

10. Trust Unit Rights Incentive Plan

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, 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.

The Trust recorded compensation expense of $5.3 million for the year ended December 31, 2005 ($4.6 million in 2004) pursuant to rights granted under the Plan (note 3).

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights. The following assumptions were used to arrive at the estimate of fair values:

	2005	2004
Expected annual right's exercise price reduction	**$1.80**	$1.80
Expected volatility	**23%**	30%
Risk-free interest rate	**3.30% - 3.84%**	3.59% - 4.31%
Expected life of option (years)	**5**	5

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

	Number of rights	Weighted average exercise price [(1)]
Balance, December 31, 2003	2,855	$ 10.15
Granted	1,297	$ 11.77
Exercised	(113)	$ 8.87
Cancelled	(502)	$ 9.54
Balance, December 31, 2004	3,537	$ 9.60
Granted	2,451	$ 15.01
Exercised	(369)	$ 7.90
Cancelled	(253)	$ 9.83
Balance, December 31, 2005	5,366	$ 10.88

(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 December 31, 2005:

Range of Exercise Prices	**Number Outstanding at December 31, 2005**	**Weighted Average Remaining Term**	**Weighted Average Exercise Price**	**Number Exercisable at December 31, 2005**	**Weighted Average Exercise Price**
		(years)			
$ 5.41 to $ 8.50	1,959	2.7	$ 6.60	1,136	$ 6.57
$ 8.51 to $11.50	1,028	3.8	$ 10.45	323	$ 10.45
$11.51 to $14.50	472	4.4	$ 12.57	-	-
$14.51 to $17.68	1,907	4.8	$ 15.08	-	-
$ 5.41 to $17.68	5,366	3.8	$ 10.88	1,459	$ 7.43

11. Interest Expense

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

	Three Months Ended December 31		**Year Ended December 31**	
	2005	2004	**2005**	2004
Credit facility charges	**$ 2,514**	$ 1,798	**$ 8,318**	$ 2,256
Amortization of deferred charge	**458**	267	**1,492**	1,060
Long-term debt	**6,768**	4,383	**23,314**	16,096
Total interest	**$ 9,740**	$ 6,448	**$ 33,124**	$ 19,412

12. Supplemental Cash Flow Information

	Three Months Ended December 31		Year Ended December 31	
	2005	2004	**2005**	2004
Interest paid	**$ 5,841**	$ 1,799	**$ 29,728**	$ 21,096
Income taxes paid	**$ 1,593**	$ 2,408	**$ 8,536**	$ 17,485

13. Financial Derivative Contracts

At December 31, 2005, the Trust had derivative contracts for the following:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

FOREIGN CURRENCY

	Period	Amount	Floor	Cap
			CAD$/US$	CAD$/US$
Collar	Calendar 2006	US$3,000,000 per month	$1.1700	$1.2065

INTEREST RATE SWAP

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

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

In 2006, the Company entered into derivative contracts for the following:

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

FOREIGN CURRENCY

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

14. COMMITMENTS AND CONTINGENCIES

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

At December 31, 2005, the Trust had entered into natural gas physical sales contracts with third parties as follow:

GAS

	Period	Volume	Price
Fixed price	January 1, 2006 to February 28, 2006	3,000 GJ/d	CAD$10.00
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.07
Fixed price	January 1, 2006 to October 31, 2006	5,000 GJ/d	Range between CAD$8.40 - $10.20
Fixed price	January 1, 2006 to March 31, 2006	2,000 GJ/d	CAD$10.63
Fixed price	March 1, 2006 to March 31, 2006	3,000 GJ/d	CAD$11.53
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	January 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 - $13.40
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 - $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 – $12.60

At December 31, 2005 the Trust had operating lease and transportation obligations as detailed below:

	Payments Due			
($thousands)	Total	Within 1 year	1-3 years	4-5 years
Operating leases	8,117	1,621	5,834	662
Transportation agreements	3,446	2,052	1,394	-
Total	11,563	3,673	7,228	662

At December 31, 2005, there are outstanding letters of credit aggregating $7.1 million issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired in the Stoddart area. 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 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.