MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated March 8, 2006, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2005 and 2004. Per 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.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), recycle ratio and total capitalization to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2005 and 2004, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made.

DEREK AYLESWORTH
CHIEF FINANCIAL OFFICER

Mr. Aylesworth is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management as well as the tax and treasury functions.

The Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

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

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. 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.

2005 OVERVIEW

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.

On September 30, 2005 we completed the acquisition of certain heavy oil producing properties in the Celtic area in Saskatchewan for a net cash consideration of $69 million. The assets acquired consisted of 3,350 bbl/d of heavy oil (13 – 15 API) and 0.9 MMcf/d of natural gas. Production from this acquisition represented approximately 10 percent of our existing production. The assets acquired also included approximately 7,500 net acres of undeveloped land. The Celtic properties are situated approximately 30 miles east of Lloydminster and are adjacent to Tangleflags, Baytex's second largest producing area within its heavy oil operations. The expanded Celtic/Tangleflags operating region will improve economies of scale and allow for better control over costs. The acquisition also included in excess of 100 opportunities for development drilling and recompletions for additional primary (cold) heavy oil production and natural gas production which added immediate low-cost development inventory. The acquisition also included 1,750 bbl/d of SAGD (steam assisted gravity drainage) production, representing Baytex's first steam-assisted enhanced recovery project. As part of this transaction, Baytex has entered into a price-sharing arrangement and a net profits agreement for future SAGD development with the vendor with respect to the assets acquired.

On December 30, 2005 we sold the recently acquired SAGD assets in the Celtic area of Saskatchewan for a net cash consideration of $45.3 million. These proceeds were used to repay bank borrowings.

PERSPECTIVE

"The financial position of Baytex has never looked brighter. Our 2006 cash flow is protected with solid commodity price contracts, we have an inventory which allows us to replace production inexpensively, and our balance sheet offers us much financial flexibility."

PROPERTY REVIEW

Principal Properties

Baytex's crude oil and natural gas operations are organized into two operating districts – the Heavy Oil District and the Light Oil and Natural Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established several geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation and execution of exploration, development and acquisition opportunities and improves cost efficiency.

Heavy Oil District

The Heavy Oil District accounts for approximately 60 percent of current production, three-quarters of oil-equivalent reserves and one-half of cash flow from operations. Baytex's heavy oil operations consist largely of cold primary production, without the assistance of steam injection. In some cases, heavy oil reservoirs containing lower-than-average viscosity crudes are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 bbl/d of low gravity crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. The crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers.

In 2005, production in the Heavy Oil District averaged 21,265 bbl/d of heavy oil and 7.5 MMcf/d of natural gas (22,515 boe/d). Baytex drilled 67 (65.4 net) wells in the Heavy Oil District resulting in 59 (57.4 net) oil wells, one (1.0 net) gas well, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96 percent (95 percent net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River/Seal heavy oil sands. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to offsetting the Trust's overall production decline rate. Because of Baytex's large inventory of heavy oil investment projects, the Trust is able to regulate the timing and level of its capital investment program while generally maintaining production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus on the development of the Seal field and the newly acquired Celtic property, along with continued drilling and re-completion activity throughout Baytex's Saskatchewan properties. Company net undeveloped lands in this district totalled approximately 313,900 acres at year-end 2005.

ARDMORE: Acquired in 2002 at a production rate of 2,200 bbl/d, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2005 was approximately 4,100 bbl/d of oil and 800 Mcf/d of natural gas (4,200 boe/d). Current production is approximately 3,900 bbl/d and 700 Mcf/d of natural gas (4,000 boe/d). Sixteen successful oil wells and no dry holes were drilled in the area during 2005.

During 2006, Baytex anticipates drilling eight to ten wells. In 2005, operating expenses were maintained at $5.50/boe by using a Company-owned water disposal facility and continuing to conserve solution gas that is produced in conjunction with the heavy oil. Company net undeveloped lands were 41,800 acres at year-end 2005.

CARRUTHERS: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. A typical vertical oil well will initially produce at 40 bbl/d and provide an ultimate recovery of approximately 60,000 barrels of reserves. During 2005, average production was approximately 2,700 bbl/d of heavy oil and 900 Mcf/d of natural gas (2,900 boe/d). Five successful oil wells were drilled in South Carruthers during 2005. This area represents a very stable production base with continued development drilling expected to total three to five wells annually. Current production is approximately 2,900 bbl/d and 900 Mcf/d of natural gas (3,100 boe/d). Company net undeveloped lands were 12,400 acres at year-end 2005.

CELTIC: This producing property was acquired in October 2005, in a transaction which included approximately 1,750 bbl/d of SAGD production. The SAGD production was divested at the end of 2005, leaving Baytex with the cold heavy and gas production from this property. At the time of the purchase, cold production rates were approximately 1,600 bbl/d of heavy oil and 0.9 MMcf/d of natural gas. Current production has increased to over 3,000 boe/d. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a huge resource base (455 million barrels of original oil in-place) within multiple prospective horizons. The Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil is relatively gas saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2006, Baytex expects to drill 30 wells and recomplete 25 to 30 additional wells. In addition, it is anticipated that between 500 and 1,000 Mcf/d of solution gas sales will be added through on-going tie-in projects. Company net undeveloped lands were 7,100 acres at year-end 2005.

COLD LAKE: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily generated from the Colony formation. Average oil production was 700 bbl/d for 2005, during which time Baytex drilled two (1.8 net) oil wells and no dry wells. Current production is approximately 670 bbl/d. Up to five new drills are anticipated during 2006. Company net undeveloped lands were 15,000 acres at year-end 2005.

MARSDEN/EPPING/MACKLIN/SILVERDALE: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oils that range up to 18 API gravity. Initial production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30 percent of the original oil in place because many of the oil pools in this area have a strong natural water drive. Average oil production in this area during 2005 was approximately 4,400 bbl/d. Eight oil wells were drilled in 2005 and current oil production is approximately 3,600 bbl/d. In addition, a solution gas tie-in project that currently sells 300 Mcf/d of natural gas was completed at Marsden. During 2006, a 300 Mcf/d solution gas project at Macklin is expected to be put on-stream and eight to 10 new wells are planned. Company net undeveloped lands were 19,600 acres at year-end 2005.

SEAL: Seal is a highly prospective property located in the Peace River oil sands area of northwest Alberta. Baytex holds a 100 percent working interest in approximately 100 sections of long-term oil sands leases. These oil deposits can be produced through horizontal well-bores at initial rates of approximately 150 bbl/d without resorting to more capital intensive steam injection methods. A four-well stratigraphic test program completed during the first quarter of 2005 proved up significant extensions to our current development area located on the western block of these land holdings. Six horizontal wells drilled in late 2004 and early 2005 are currently producing approximately 500 bbl/d. The prospective undeveloped area of this westernmost block of Baytex leases comprises over 25,000 acres, and during 2006 we will drill three additional stratigraphic test wells to further delineate this acreage. In addition, two multi-lateral horizontal wells drilled with upper and lower production legs to more efficiently tap the 20 meter thick oil sand deposit will be completed and brought on-stream in 2006. Operators of adjoining lands are pursuing aggressive development programs that will contribute to vital infrastructure and allow enhanced marketing solutions for the region. As the region continues to develop, the Seal property will take an increasingly more prominent role in the Trust's development activities. Company net undeveloped lands in this area were 67,000 acres at year-end 2005.

TANGLEFLAGS: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. As such, this property supplies longer-term development potential through a considerable number of uphole recompletion opportunities. Average production during 2005 was approximately 3,500 bbl/d of heavy oil and 1.4 MMcf/d of natural gas (3,700 boe/d). Current production is approximately 3,000 bbl/d and 2.1 MMcf/d. The growth in natural gas production was achieved through the conservation of solution gas produced in conjunction with the heavy oil. During 2006, Baytex plans to add three to five new wells, conduct 10 to 20 recompletions and continue tie-in of solution gas production. Company net undeveloped lands were 10,200 acres at year-end 2005.

Light Oil and Natural Gas District

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties that currently provide approximately half of our cash flow. When Baytex converted from a traditional E&P company to an energy trust in 2003, Baytex Energy Trust produced approximately 12,000 boe/d of light oil and natural gas concentrated in southeastern and northern Alberta. Over the last two and a half years, Baytex's light oil and gas production has grown to its current level of approximately 14,000 boe/d through a combination of acquisitions and development activities. Moreover, the geographic scope of our light oil and gas operations has expanded to southwest Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2005, production averaged 52.9 MMcf/d of natural gas and 3,842 bbl/d of hydrocarbon liquids (12,662 boe/d). In 2005, the District drilled 51 (41.9 net) wells resulting in 40 (33.4 net) gas wells, five (3.0 net) oil wells, and six (5.5 net) dry and abandoned wells for a success rate of 88 percent (88 percent net). Company undeveloped lands in this district were approximately 425,600 net acres at year-end 2005.

BON ACCORD, ALBERTA: This multi-zone property was acquired by Baytex in 1997. Production, which is from the Belly River, Viking and Mannville formations, averaged approximately 6.0 MMcf/d of gas and 300 bbl/d of hydrocarbon liquids (1,300 boe/d) in 2005. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. Baytex plans to drill three wells in this area during 2006. Company net undeveloped lands were 27,400 acres at year-end 2005.

DARWIN/NINA, ALBERTA: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2005 averaged approximately 4.0 MMcf/d (700 boe/d). Baytex plans to drill three wells during 2006 in the Nina/Darwin area. Company net undeveloped lands were 52,000 acres at year-end 2005.

LEAHURST, ALBERTA: Production averaged approximately 5.0 MMcf/d (800 boe/d) in 2005 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. In 2005, Baytex drilled 14 (11.3 net) wells for coalbed methane production from the Horseshoe Canyon Coals (three of which were also completed in the Belly River formation), and four (4.0 net) Mannville natural gas wells. In 2006, Baytex may drill up to 12 Horseshoe Canyon CBM/Belly River wells and one Mannville well in the Leahurst area. Company net undeveloped lands were 20,600 acres at year-end 2005.

RED EARTH/GOODFISH, ALBERTA: This winter-access, multi-zone property was acquired by Baytex in 1997. Relatively shallow decline oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production during 2005 from this area averaged approximately 6.0 MMcf/d and 900 bbl/d of hydrocarbon liquids (1,900 boe/d). Baytex plans to drill four wells during 2006 in the Red Earth/Goodfish area. Company net undeveloped lands were 49,900 acres at year-end 2005.

RICHDALE/SEDALIA, ALBERTA: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition. During 2005, production averaged approximately 9.0 MMcf/d and 21 bbl/d of hydrocarbon liquids (1,500 boe/d). This area has advantages of year-round access and multi-zone potential (Second White Specks, Viking and Mannville). Most of the gas production is processed by two Company-operated gas plants. Baytex plans to drill three wells during 2006 in this area. Company net undeveloped lands were 60,300 acres at year-end 2005.

STODDART, BRITISH COLUMBIA: The Stoddart asset acquisition was completed in December 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Company-operated batteries and natural gas is compressed at four Company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production during 2005 from this area averaged approximately 12.0 MMcf/d and 1,700 bbl/d of hydrocarbon liquids (3,700 boe/d). Baytex drilled nine wells in 2005 resulting in eight gas wells and one abandoned well, and plans to drill six wells and recomplete three wells in 2006. Company net undeveloped lands were 34,500 acres at December 31, 2005.

TURIN, ALBERTA: This multi-zone, year-round access property was acquired in 2004. Production during 2005 averaged approximately 2.0 MMcf/d and 700 bbl/d of hydrocarbon liquids (1,000 boe/d). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. Baytex plans to drill three wells and recomplete five additional wells during 2006 in the Turin area. Company net undeveloped lands were 29,500 acres at December 31, 2005.

MARKETING

Crude Oil

World crude oil prices rose in 2005 as strong economic growth combined with supply disruptions and geopolitical events to continue the upward momentum from 2004. World demand for oil and products grew by 1.3 percent in 2005, a modest increase following the enormous growth of 3.8 percent in 2004. The resulting price increase demonstrated that crude oil and products supplies were not able to respond to the continued demand growth as the world's drilling and refining operations were already operating at capacity. In North America, the largest impact on crude oil supplies came from Hurricanes Katrina and Rita in August and September 2005. Much of U.S. Gulf of Mexico oil and gas producing operations were forced offline, losing approximately 110 million barrels of cumulative oil production through year-end.

The lack of excess OPEC productive capacity also contributed to record prices in 2005. After increasing production in late 2004 to meet surging Asian demand, OPEC production remained fairly flat. Geopolitical events again played a role as the ongoing conflict in Iraq, unrest in Nigeria, politics in Russia and the more-recent Iranian nuclear stand-off have left market participants very nervous.

Benchmark WTI prices began the year around US$42.00 per bbl, climbed to an all-time high of US$69.81 per bbl on August 30th, and ended the year over US$61 per bbl. The average WTI price for 2005 was US$56.56 per bbl, an increase of 37 percent from US$41.40 in 2004.

Canadian crude oil prices, while enjoying the strength in world prices, were tempered by the rising Canadian dollar against its U.S. counterpart. Canadian Par crude at Edmonton averaged $68.75 per bbl in 2005, up 31 percent from $52.57 in 2004.

With OPEC increasing production in late 2004, supplies of heavy and sour crude oil increased and prices versus benchmark light sweet prices deteriorated during 2005. Canadian heavy oil prices mirrored this trend as the differential between WTI and Lloyd blend prices in Alberta averaged US$21.82 per bbl in 2005 (39 percent of WTI) compared to US$14.01 per bbl in 2004 (34 percent of WTI).

Baytex's light oil and natural gas liquids prices averaged $53.84 per bbl before hedging in 2005 compared to $48.64 in 2004. Our heavy oil prices averaged $37.38 per bbl in 2005, compared to $30.32 in 2004.

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 bbl/d of Lloyd Blend (LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 16,000 barrels of Baytex production and 4,000 bbl/d of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term average differential since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil operations.

RALPH GIBSON
VICE PRESIDENT,
MARKETING

Mr. Gibson is responsible for the transportation and marketing of Baytex's production and implementing the Trust's commodity price risk mitigation strategies.

Going forward, Baytex has entered into a series of costless collar contracts which will provide significant downside protection on the oil price while still allowing Baytex to participate in upside price potential. WTI costless collars have been put in place for 2006 on 8,000 bbl/d at a weighted average price from US$55.00 to US$84.39 per bbl and for 5,000 bbl/d for 2007 at a weighted average price from US$55.00 to US$83.69 per bbl.

Baytex is working to develop a solution to the marketing and infrastructure issues present in the Seal area and management is optimistic that solutions can be developed which will accelerate full-scale field development.

Natural Gas

Natural gas prices in North America were strong again in 2005, reflecting high oil prices, concerns over gas supplies and the severe loss of production from the hurricane activity, where 570 Bcf of production was lost during the fourth quarter. U.S. gas prices represented by the NYMEX futures contract averaged US$8.55 per Mcf in 2005, an increase of 40 percent from US $6.09 in 2004. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.71 per Mcf in 2005, up 33 percent from $6.53 in 2004. Five-year averages are US$5.54 per Mcf for the NYMEX contract and $6.00 for Alberta daily prices.

Baytex received an average of $8.22 per Mcf for 2005 natural gas sales compared to $6.46 in 2004.

For 2006 Baytex has entered into several physical forward sales contracts. These agreements have locked in seasonal natural gas prices over the year at prices above the current forward strip.

PERSPECTIVE

"Marketing is the final link in the value chain. We strive to enhance the Company's revenues by minimizing transportation costs and ensuring we are selling our products to credit-worthy counterparties at fair market value. It's a dynamic and challenging environment."

OPERATIONS

Production

The Trust's average production for fiscal 2005 increased by three percent to 35,177 boe/d from 34,022 boe/d for fiscal 200.

Light oil and NGL production increased by 76 percent to 3,842 bbl/d from 2,172 bbl/d for last year. Heavy oil production for 2005 was down seven percent to 21,265 bbl/d compared to 22,703 bbl/d in 2004. Natural gas production increased by 10 percent 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 is due to the acquisition completed in 2004 and the subsequent development of these assets. The decrease in heavy oil production is due to the reduction in drilling, where 66 net heavy oil wells were drilled in 2005 compared to 95 net wells drilled in 2004.

Production by Area

	Light Oil and NGL	*Heavy Oil*	*Natural Gas*	*Oil Equivalent*
	(bbl/d)	*(bbl/d)*	*(MMcf/d)*	*(boe/d)*
2005				
Heavy Oil District	–	21,265	7.5	22,515
Light Oil and Natural Gas District	3,842	–	52.9	12,662
Total production	3,842	21,265	60.4	35,177
2004				
Heavy Oil District	–	22,703	8.9	24,177
Light Oil and Natural Gas District	2,172	–	46.0	9,845
Total production	2,172	22,703	54.9	34,022

Revenue

Petroleum and natural gas sales for 2005 increased by four percent to $546.9 million from $420.4 million for fiscal 2004. Benchmark WTI crude oil averaged US$56.56 per barrel for 2005, representing a 37 percent increase over the US$41.40 per barrel for 2004. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$ 0.8253 in 2005 compared to US$ 0.7683 in 2004. The Trust's light oil and NGL price increased to $53.84 per barrel from $48.64 per barrel. The heavy oil price increased 23 percent to $37.38 per barrel in 2005 from $30.32 per barrel in 2004. Natural gas prices were 27 percent higher in 2005, averaging $8.22 per Mcf compared to $6.46 per Mcf during the previous year. Overall, after accounting for $48.5 million of realized losses on financial derivative contracts, the Trust averaged $38.82 per boe for 2005, a 41 percent increase from $27.48 per boe received in the prior year.

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

Gross Revenue Analysis	2005		2004	
	$ thousands	*$/Unit (1)*	*$ thousands*	*$/Unit (1)*
Oil revenue *(barrels)*				
Light oil and NGL	**75,507**	**53.84**	38,673	48.64
Heavy oil	**290,163**	**37.38**	252,016	30.32
Derivative contract 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.

Royalties

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 percent of sales, compared to 15.7 percent of sales for 2004. For 2005, royalties were 15.1 percent of sales for light oil and NGL, 12.4 percent for heavy oil and 19.0 percent for natural gas. These rates compared to 14.1 percent, 13.3 percent and 20.9 percent, 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 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 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.

Net Revenue

	Light Oil & NGL ($/bbl)		*Heavy Oil ($/bbl)*		*Total Oil & NGL ($/bbl)*		*Natural Gas ($/Mcf)*		*BOE ($/boe)*	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Sales price	**53.84**	48.64	**37.38**	30.32	**39.90**	31.91	**8.22**	6.46	**42.60**	33.75
Royalties	**(8.13)**	(6.88)	**(4.63)**	(4.02)	**(5.17)**	(4.27)	**(1.57)**	(1.35)	**(6.38)**	(5.30)
Operating costs	**(9.06)**	(9.51)	**(9.56)**	(7.83)	**(9.48)**	(7.97)	**(1.08)**	(0.82)	**(8.62)**	(7.15)
Transportation	**(1.16)**	(0.92)	**(2.28)**	(1.73)	**(2.11)**	(1.66)	**(0.14)**	(0.18)	**(1.74)**	(1.50)
Net revenue	**35.49**	31.33	**20.91**	16.74	**23.14**	18.01	**5.43**	4.11	**25.86**	19.80

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

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.

($ thousands)	**2005**	2004
Gross corporate expenses	**22,568**	20,413
Operator's recoveries	**(6,558)**	(5,170)
Net expenses	**16,010**	15,243

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $5.3 million for 2005 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 or decrease 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 awards at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing options 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 Expense

In 2005, interest expense was $33.1 million for the year compared to $19.4 million last year. The increase in total interest expense is primarily due to the increased debt used to finance acquisitions completed in 2004, plus a gradual increase in interest rates.

Foreign Exchange

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

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 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.

The fiscal 2005 provision for future income taxes was a recovery of $7.1 million compared to a recovery of $41.2 million for the prior year. The future income tax recovery for 2004 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income.

Canadian Tax Pools *($ thousands)*	**2005**	2004
Cumulative Canadian Exploration Expense	**4,953**	1,283
Cumulative Canadian Development Expense	**129,596**	99,741
Cumulative Canadian Oil and Gas Property Expense	**162,974**	155,930
Undepreciated Capital Cost	**179,009**	195,235
Other	**31,087**	39,430
Total tax pools	**507,619**	491,619

Cash Flow from Operations

Cash flow from operations in 2005 increased 67 percent to $227.5 million from $136.0 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was $17.72 for 2005 compared to $10.03 for 2004. The increase is due to higher sales revenue and a lower realized loss from financial derivative contracts in 2005.

Cash Flow Netbacks	**2005**		2004	
	$/boe	*Percent*	*$/boe*	*Percent*
Production revenue	**42.60**	100	**33.75**	100
Derivative contract loss	**(3.77)**	(9)	**(6.27)**	(19)
Royalties	**(6.38)**	(15)	**(5.30)**	(16)
Operating expenses	**(8.62)**	(20)	**(7.15)**	(21)
Transportation	**(1.74)**	(4)	**(1.50)**	(4)
Operating netbacks	**22.09**	52	**13.53**	40
General and administrative expenses	**(1.25)**	(3)	**(1.22)**	(4)
Interest expense	**(2.44)**	(6)	**(1.56)**	(4)
Current taxes	**(0.68)**	(1)	**(0.72)**	(2)
Cash flow netbacks	**17.72**	42	**10.03**	30

Net Income

Net income for 2005 was $79.9 million compared to $16.8 million for 2004. The increased petroleum and natural gas sales realized through higher wellhead prices in 2005 were offset by increased operating expenses, a lower foreign exchange gain and a lower future income tax recovery. Net income for each year has also been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income relating to the outstanding exchangeable shares.

Capital Expenditures

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

For the year ended December 31, 2005, the Trust 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 compared to prior year activities of 138 (135.0 net) wells, including 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) stratigraphic test wells and 11 (11.0 net) dry holes. 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 SAGD production just acquired for $45.3 million. The decision to acquire these 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.

	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)
Total capital expenditures	**152,449**	280,666

Liquidity and Capital Resources

At December 31, 2005, total net debt (including working capital, but excluding notional mark-to-market assets or liabilities) was $423.7 million compared to $412.5 million at December 31, 2004. The modest increase in total debt at year-end 2005 compared to 2004 is reflective of the Trust's ability to fund distributions and capital expenditures by cash flow from operations.

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.

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2005 at total of $123.6 million had been drawn under the credit facilities.

Another component of the Company's debt is the US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010. They are unsecured and are subordinate to the Company's bank credit facilities. 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 percent until the maturity of these notes.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to unitholders where the distribution would or could have a material adverse effect on the Trust's or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

UNITHOLDERS' EQUITY

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

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95 percent of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued for treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus.

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 cash or the issue of trust units. At December 31, 2005, there were 1.6 million exchangeable shares outstanding. During 2005, a total of 0.3 million exchangeable shares were exchanged for trust units. The number of trust units issuable 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 of 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 (December 31, 2004 – 1.21472 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 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.

Cash Distributions

During 2005 total cash distributions of $1.80 per unit were declared. The monthly cash distribution of $0.15 per unit has been maintained since the inception of the Trust in September 2003 and was increased to $0.18 per unit in 2006.

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Contractual Obligations at December 31, 2005

($ thousands)		*Payments Due*		
	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 obligations	11,563	3,673	7,228	662

The Trust also has ongoing obligations related to the abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

Risk and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Company's Board of Directors, assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserve estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, The Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in US dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the US dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates. Changes in interest rates also impact the Company's interest rate swap contract which converts the fixed interest rate of 9.625 percent on the US$179.7 million notes to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

The Trust's current position with respect to its financial derivative contracts is detailed in note 17 of the consolidated financial statements.

A summary of certain risk factors relating to our business is included in our Annual Information Form under the Risk Factors section.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil and Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserves estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserves estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserves estimates are revised downward, net income could be affected by increased depletion and depreciation.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result a significant accounting loss for a particular period.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated 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. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

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 awards at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing options 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 increased 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.

NEW ACCOUNTING PRONOUNCEMENTS

Financial Instruments

In January 2005 the CICA issued three new standards relating to the reporting of financial instruments in financial statements. These standards introduce new requirements for the recognition and measurement of financial instruments and comprehensive income. Section 3855, "Financial Instruments – Recognition and Measurement" requires that all financial instruments, including derivatives, are to be included on a company's balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. The standard also provides guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement.

The issuance of the new Section 3855 will result in amendments to Section 3860 "Financial Instruments – Disclosure and Presentation" to make the scope and definitions consistent with that of the new Section 3855, including expanding the scope to include certain commodity-based contracts, and to update certain disclosures in light of the introduction of Section 3855. Other Handbook Sections have also been amended for conformity with the new standards.

Section 3865 "Hedges", extends the existing requirements for hedge accounting currently under AcG-13. This new section allows for the optional treatment of accounting for financial instruments that are designated as either fair value hedges, cash flow hedges or hedges of a net investment in a self-sustaining foreign operation. For a fair value hedge, the gain or loss on a derivative hedging item, or the gain or loss on a non-derivative hedging item attributable to the hedged risk, is recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. The carrying amount of the hedged item is adjusted for the hedged risk. For a cash flow hedge, the effective portion of the hedging item's gain or loss is initially reported in other comprehensive income and subsequently reclassified to net income when the hedged item affects net income. For a hedge of a net investment in a self-sustaining foreign operation the same accounting is followed as for a cash flow hedge.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issued of Section 1530, "Comprehensive Income". An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders' equity, in accordance with Section 1650, "Foreign Currency Translation", will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

Non-Monetary Transactions

In June 2005, The CICA issued Section 3831 "Non-Monetary Transactions", which replaces the culmination of earnings test with a commercial substance test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

FOURTH QUARTER 2004

The following discussion reviews the Trust's results of operations for the fourth quarter of 2004.

Light oil and NGL production for the fourth quarter of 2005 increased by 44 percent to 4,022 bbl/d from 2,786 bbl/d a year earlier. Heavy oil production increased seven percent 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 six percent 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 and 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.

Petroleum and natural gas sales increased 46 percent to $162.4 million for the fourth quarter of 2005 from $111.5 million for the same period in 2004. Revenue from light oil and NGL for the fourth quarter of 2005 increased 60 percent from the same period a year ago due to a 44 percent increase in production and a 11 percent increase in wellhead prices. Revenue from heavy oil increased 29 percent due to a seven percent increase in production and a 21 percent increase in wellhead prices. Revenue from natural gas increased 72 percent as the result of a 62 percent increase in wellhead prices and a six percent increase in production.

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 percent of sales compared to 15.6 percent of sales for the same period in 2004. For the fourth quarter of 2005, royalties were 16.2 percent of sales for light oil and NGL, 11.7 percent for heavy oil and 24.3 percent for natural gas. These rates compared to 15.9 percent, 13.5 percent and 19.5 percent, respectively, for the same period last year.

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.

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.

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 general and administrative expenses were capitalized in either the fourth quarter of 2005 or 2004.

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.

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, plus a gradual increase in interest rates.

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 US 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 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.

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, offset by foreign exchange losses and an increase in future tax provision.

Trust Unit Information

At February 28, 2006, the Trust had 71,231,684 units outstanding and the Company had 1,594,733 exchangeable shares outstanding. The exchange ratio at February 28, 2006 was 1.39624 trust units per exchangeable share.

At February 28, 2006, the Trust had $55.0 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

SELECTED ANNUAL INFORMATION

Financial

($ thousands, except per unit amounts)	2005	2004 (3)	2003 (2)(3)
Revenue	**546,940**	420,400	403,022
Net income (1)	**79,876**	16,764	34,141
Per unit basic (1)	**1.19**	0.27	0.64
Per unit diluted (1)	**1.15**	0.26	0.59
Total assets	**1,105,567**	1,104,136	982,640
Total long-term financial liabilities	**283,565**	216,583	232,562
Cash distributions declared per unit	**1.80**	1.80	0.60

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements). The application of this standard did not impact the 2002 financial information.

(2) The financial information for 2003 has been restated for the adoption of the new accounting standards related to asset retirement obligations and transportation expenses.

(3) The financial information for 2004 and 2003 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

Overall production for 2005 was 35,177 boe per day which represented a three percent increase from 34,022 boe per day in 2004. Average wellhead prices received during 2005 were $42.60 per boe compared to $33.75 during 2004. Production in 2003 was 36,686 boe per day. Average wellhead prices received in 2003 were $28.07 per boe.

QUARTERLY INFORMATION

Financial *(unaudited)*

	2005				2004 (2)			
($ thousands, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**162,356**	**154,930**	**118,379**	**111,275**	111,521	108,216	104,517	96,146
Cash flow from operations	**65,487**	**67,501**	**49,937**	**44,540**	28,144	32,235	36,944	38,689
Per unit basic	**0.95**	**1.00**	**0.75**	**0.67**	0.44	0.50	0.57	0.60
Per unit diluted	**0.86**	**0.90**	**0.71**	**0.64**	0.42	0.49	0.57	0.60
Cash distributions declared per unit	**0.45**	**0.45**	**0.45**	**0.45**	0.45	0.45	0.45	0.45
Net income (loss) (1)	**35,184**	**39,524**	**16,779**	**(11,611)**	42,696	(10,672)	(10,585)	(4,674)
Per unit basic (1)	**0.51**	**0.59**	**0.25**	**(0.17)**	0.67	(0.17)	(0.17)	(0.08)
Per unit diluted (1)	**0.48**	**0.55**	**0.25**	**(0.17)**	0.66	(0.17)	(0.17)	(0.07)

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements).

(2) The financial information for 2004 and 2003 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

Production	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Light oil and NGL *(bbl/d)*	**4,022**	**4,063**	**3,404**	**3,876**	2,786	1,890	1,952	2,058
Heavy oil *(bbl/d)*	**24,051**	**20,061**	**19,653**	**21,279**	22,490	22,083	22,927	23,322
Total oil and NGL *(bbl/d)*	**28,073**	**24,124**	**23,058**	**25,155**	25,276	23,974	24,879	25,380
Natural gas *(MMcf/d)*	**58.9**	**63.9**	**59.3**	**59.5**	55.5	50.9	57.2	56.0
Oil equivalent *(boe/d @ 6:1)*	**37,895**	**34,780**	**32,937**	**35,068**	34,525	32,454	34,411	34,709
Average Prices								
WTI oil *(US$/bbl)*	**60.02**	**63.19**	**53.17**	**49.84**	48.28	43.88	38.32	35.15
Edmonton par oil *($/bbl)*	**71.18**	**76.51**	**65.76**	**61.44**	57.72	56.32	50.59	45.59
BTE light oil *($/bbl)*	**55.78**	**59.24**	**53.06**	**46.69**	50.46	52.63	47.55	43.50
BTE heavy oil *($/bbl)*	**37.75**	**45.39**	**35.71**	**30.83**	31.24	34.69	29.21	26.29
BTE total oil *($/bbl)*	**40.33**	**47.74**	**28.27**	**33.27**	33.35	36.11	30.63	27.70
BTE natural gas *($/Mcf)*	**10.69**	**8.39**	**7.08**	**6.69**	6.60	6.16	6.61	6.43
BTE oil equivalent *($/boe)*	**46.48**	**48.54**	**39.53**	**35.21**	35.03	36.34	33.12	30.63

2006 GUIDANCE

Baytex has set a $105 million exploration and development capital budget for 2006, with approximately $65 million allocated for activities relating to heavy oil and $40 million for activities relating to natural gas and light oil. Production for the year is targeted to average 35,000 boe/d, with heavy oil at 21,000 bbl/d, natural gas at 61.2 MMcf/d and light oil and NGL at 3,800 bbl/d.

Baytex has entered into the following contracts to provide downside protection to 2006 and 2007 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

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*
Collar	Calendar 2006	US$3,000,000 per month	CAD/US$1.1700	CAD/US$1.2065

INTEREST RATE SWAP

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

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

Physical Sale Contracts

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 March 31, 2006	5,000 GJ/d	CAD$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	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	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

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 17 to the December 31, 2005 consolidated financial statements for description of accounting treatment of these derivative contracts.

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.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.