MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated March 17, 2008, 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, 2007 and 2006. 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, which represents an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. BOE's may be misleading, particularly if used in isolation.

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 cash flow from operations 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 most directly comparable measure calculated in accordance with GAAP is cash flow from operating activities, and net income per unit. A reconciliation of net income to cash flow from operations and cash flow from operating activities is shown under Quarterly Information.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netback ("netback"), 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 MD&A 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, 2007 and 2006, 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. Except where required by securities legislation, 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 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") became a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of Baytex 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 Baytex. 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.

2007 OVERVIEW

The Trust strives to be self-sustaining from an operational and financial perspective, relying primarily on internal property development to provide production and reserves replacement. The Trust plans to fund its ongoing program along with distributions substantially from internally generated cash flow. Significant acquisitions may be funded through a combination of debt and equity issuance. During 2007, the Trust executed a successful capital program replacing 123% of production (on a proved plus probable basis) by spending 52% of cash flow from operations and 274% of production by an overall capital program including acquisitions, equal to 138% of cash flow.

On June 15, 2007, we completed a public offering of 7,000,000 Subscription Receipts (the "Sub Receipts") for gross proceeds of $149,450,000. Upon the June 26, 2007 closing of the property acquisition described below, the holders of the Sub Receipts received one trust unit in exchange for each Sub Receipt held. The net proceeds of this financing were used to partially fund the acquisition of properties at Pembina and Lindbergh.

On June 26, 2007, we completed the acquisition of certain oil and gas properties in the Pembina and Lindbergh areas of Alberta for total cash consideration of $241 million. These assets were producing approximately 4,500 barrels of oil equivalent per day ("boe/d") of total production at the time of the acquisition. This production was comprised of 2,200 barrels per day ("bbl/d") of light oil and NGL and 8.0 million cubic feet per day ("MMcf/d") of natural gas from the Pembina area, and 1,000 bbl/d of heavy oil from the Lindbergh area. The acquisition in the Pembina area allowed us to establish a new core area in the Nisku trend, offering greater exposure to high netback light oil and NGL targets. The assets included one of the strongest infrastructure positions in the area, which contributed to our high degree of operational control of the area, and included 26,000 net acres of undeveloped land in the Pembina area. Lindbergh is a project that offers a large heavy oil resource in place that is amenable to primary (cold) production. Its shallow-depth and multiple zone character provide a low-cost source of recompletion and drilling inventory to maintain production rates. In addition to the primarily non-operated producing assets, Baytex also acquired 11,000 net acres of 100% interest undeveloped land that may include opportunities for shallow natural gas development.

PROPERTY REVIEW

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2007. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2007, except where otherwise indicated.

Baytex's crude oil and natural gas operations are organized into two operating districts: the Heavy Oil District and the Conventional Oil and Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these districts, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Heavy Oil District

The Heavy Oil District accounts for more than 55% of current production, more than 70% of oil-equivalent reserves and over half of Baytex's cash flow from operations. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's 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 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. Heavy crude is usually blended with a light-hydrocarbon diluent (such as condensate) prior to being introduced into a sales pipeline. The blended 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. All production rates reported are for heavy crude only, before the addition of diluent.

In 2007, production in the Heavy Oil District averaged approximately 22,100 bbl/d of heavy oil and 7,340 Mcf/d of natural gas (23,400 boe/d). Baytex drilled 94 gross (93.5 net) wells in the Heavy Oil District resulting in 87 (86.5 net) oil wells, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96.8% (96.8% net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River areas. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of Baytex's large inventory of heavy oil investment projects, we are able to select between a wide range of investments to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's area of historical emphasis around Lloydminster in southwest Saskatchewan and southeast Alberta. Our net undeveloped lands in the Heavy Oil District totalled approximately 295,000 acres at year-end 2007. Our key heavy oil properties are described below.

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2007 was approximately 1,900 bbl/d of oil and 480 Mcf/d of natural gas (2,000 boe/d). Three successful oil wells and no dry holes were drilled in the area during 2007. Baytex anticipates drilling three wells in this area in 2008. In addition, new production techniques, such as cold horizontal well production and cyclic steam injection, are being evaluated for the large hydrocarbon resource in this area. Due to extensive Baytex infrastructure in this area, operating expenses in 2007 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2007.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate “North” and “South” oil pools in the Cummings formation. During 2007, average production was approximately 2,300 bbl/d of heavy oil and 780 Mcf/d of natural gas (2,400 boe/d). No new wells were drilled in this area in 2007 but the hot waterflood project was expanded by flowlining to eight existing wells and converting five wells to injection. Net undeveloped lands were 9,900 acres at year-end 2007.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction which included approximately 2,000 Bbl/d of Steam Assisted Gravity Drainage (SAGD) production. The SAGD production was divested at the end of 2005, leaving Baytex with purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex’s well re-completion and drilling activities, cold production increased to an average of 4,500 bbl/d of heavy oil and 1,330 Mcf/d of natural gas (4,700 boe/d) during 2007. This production number includes minor production in the area held prior to the Celtic acquisition. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base within multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of low-cost drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2008, Baytex expects to drill 25 new wells and re-complete up to 70 existing wells. Net undeveloped lands were 8,300 acres at year-end 2007.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2007 was approximately 600 bbl/d, during which time Baytex drilled two oil wells. Two new wells are planned for 2008. Net undeveloped lands were 13,600 acres at year-end 2007.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2007 was approximately 2,400 bbl/d of oil and 110 Mcf/d of natural gas (2,500 boe/d). Nine oil wells and one dry hole were drilled in this region in 2007. For 2008, 26 new wells are planned for this area including a 16 well development program to expand the Silverdale Sparky oil pool. A significant facility expansion involving emulsion flow-lining and conservation of the solution gas is also planned for this pool. Net undeveloped lands were 24,300 acres at year-end 2007.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in over 100 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced through primary methods using horizontal wells at initial rates of approximately 150 bbl/d per well without employing more capital-intensive methods such as steam injection. During 2007, Baytex drilled four new stratigraphic test wells to identify extensions to our current development area which is located on the western block of these land holdings. Baytex also drilled 17 new horizontal producing wells in 2007, bringing the total number of producing wells to 25. The average production rate during 2007 was 1,600 bbl/d of heavy oil. Baytex plans to drill four additional stratigraphic test wells and 15 to 20 horizontal producing wells at Seal during 2008. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase the ultimate recovery factor beyond what is achievable with primary recovery. A horizontal well drilled in 2007 was equipped for steam injection. Following approximately six months of primary production, this thermal test well will undergo an initial cycle of steam injection commencing in the first half of 2008. Baytex also intends to expand the area facilities in the first half of 2008 by constructing a water disposal plant and fuel gas supply pipeline. As the region continues to develop, the Seal property is expected to take an increasingly more prominent role in our production profile. Net undeveloped lands in this area were 56,000 acres at year-end 2007.

Tangleflags, Saskatchewan: 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. Accordingly, this property supplies long-term development potential through a considerable number of uphole re-completion opportunities. In 2007, 16 wells were either re-started or re-completed. Average production during 2007 was approximately 1,800 bbl/d of heavy oil and 950 Mcf/d of natural gas (2,000 boe/d). In 2008, Baytex plans to drill two new wells and re-work about 20 existing wells in this area. Net undeveloped lands were 8,900 acres at year-end 2007.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.15% working interest that yields working interest production of approximately 900 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky, and Colony intervals. Baytex expects the field operator to maintain a level of activity that would result in relatively flat production rates. Net undeveloped lands were 11,000 acres at year end 2007.

Conventional Oil and 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 generate nearly half of our cash flow. In addition to Baytex’s historical light oil and natural gas properties in northern and southeastern Alberta, the geographic scope of our conventional 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 Conventional Oil and Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2007, production from this district averaged approximately 44,500 Mcf/d of natural gas sales and 5,500 bbl/d of light oil and NGL for annual average oil equivalent production of 12,900 Boe/d. During 2007, the District drilled 39 gross (34.0 net) wells resulting in 22 gross (17.5 net) gas wells, 10 gross (9.7 net) oil wells, three gross (2.8 net) service wells and four gross (4.0 net) dry wells for a success rate of 90.0% (88.2% net). Our net undeveloped lands in this District were approximately 344,000 acres at year-end 2007. Our key conventional oil and natural gas properties are described below.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2007, production for the area averaged approximately 3,140 Mcf/d of gas and 300 bbl/d of light oil (800 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2007, Baytex drilled three oil wells in this area. At year-end 2007, Baytex had 15,000 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2007 averaged approximately 2,900 Mcf/d (500 boe/d). During 2007, Baytex installed an amine facility at Darwin to remove carbon dioxide from the sales gas and improve operating capability and product netback for the area. At year-end 2007, Baytex had 41,000 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 3,900 Mcf/d (700 boe/d) during 2007 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2007, Baytex participated in the drilling of 10 operated and three non-operated locations, resulting in 13 producing gas wells. During 2008, Baytex plans to drill up to five wells in this area. At year-end 2007, Baytex had 14,900 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its position in this area in June 2007. Production is primarily obtained from the Nisku formation and to a lesser extent from the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg formations. The majority of Baytex’s production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered for further processing to a combination of four mid-stream gas processing facilities in the area. From July to December 2007, production averaged approximately 3,900 bbl/d of light oil and and NGL and 7,800 Mcf/d of gas (5,200 boe/d). During 2007, Baytex drilled two Nisku tests that, while unsuccessful in the targeted formation, were cased as potential water source wells to support future water injection requirements. Baytex plans to drill four gross wells in this area during 2008. At year-end 2007, Baytex had 11,200 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. During 2007, production averaged approximately 7,300 Mcf/d of gas (1,200 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas production from this area is processed at two Baytex-operated gas plants. During 2007, Baytex drilled three gas wells in this area. At year-end 2007, Baytex had 36,100 net undeveloped acres in this area.

Red Earth/Goodfish, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2007 averaged approximately 4,330 Mcf/d of and 600 bbl/d of light oil and NGL (1,300 boe/d). During 2007, Baytex drilled one oil well in this area. At year-end 2007, Baytex had 33,700 net undeveloped acres in this area.

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 Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2007 averaged approximately 11,200 Mcf/d of gas and 1,800 bbl/d of oil and NGL (3,700 boe/d). Baytex drilled 11 wells in 2007 resulting in seven oil wells and four dry holes. During 2008, Baytex plans to drill up to six wells and re-complete several wells in the area. At year-end 2007, Baytex had 33,300 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004 with the acquisition of a private company. Production during 2007 averaged approximately 600 bbl/d of oil and NGL and 1,990 Mcf/d of gas (900 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2007, Baytex drilled one gas well and one oil well in this area. At year-end 2007, Baytex had 11,800 net undeveloped acres in this area.

United States

Baytex opened an office in Denver, Colorado during 2007 with the mandate of acquiring and developing oil and gas assets in the United Sates. Baytex's objectives in making U.S. investments are to increase geographical, product mix and currency diversification; to expose Baytex to a larger set of investment opportunities; to enhance long-term growth; and to better match Baytex's asset base to its investor base. At present, Baytex has conducted land acquisition activities in Wyoming and Utah, with first drilling expected in the second quarter of 2008. Baytex has no oil or gas production in the U.S. at present. At year-end 2007, Baytex had 10,200 net undeveloped acres in the United States.

MARKETING

Crude Oil

The year 2007 was marked by the unprecedented rise in world oil prices. OPEC cut oil output late in 2006 and again on February 1, 2007 to meet their pricing targets. Prices rose significantly on the back of supply uncertainty and moderate global demand growth. In January world crude oil prices were in the low US$50.00/bbl range and climbed steadily thereafter to nearly double in November. Overall we saw West Texas Intermediate ("WTI") – the proxy for world oil price – rise by 58% in 2007, the biggest annual rise so far this decade. World demand for oil and products grew by about 1.1% in 2007 compared to 1.3% in 2006, reflecting slower growth in North American and European demand offset by continued strength in Asian demand. Supply concerns dominated the market as inventories fell to below the 5 year trend line.

The ongoing sub-prime mortgage and credit crisis in the U.S. created much uncertainty in the financial and commodity markets, adding to price volatility. For the most part, these financial considerations overshadowed geopolitical events in spite of the protracted conflicts in Iraq and Afghanistan and the fear of Iran's potential development of nuclear capabilities.

Benchmark WTI prices began the year around US$54.00 per barrel, climbed to an all-time high of US$99.29 in November, and ended the year at close to US$96.00. The average price for 2007 was US$72.31 per barrel compared to US$66.22 in 2006, an increase of 9%. The 5-year WTI average is US$53.51 per barrel.

Canadian crude oil prices, while enjoying the strength in world prices, were offset to a large degree by the strengthening of the Canadian dollar. Canadian Par crude at Edmonton averaged $76.38 per barrel in 2007 versus $72.80 per barrel in 2006, up only 5% for the year. The 5-year Canadian Par average price is $62.73 per barrel.

Canadian heavy sour crude price differentials widened out to nearly US$42.00 per barrel for Lloydminster Blend crude ("LLB") in December 2007 due to downstream refinery and pipeline operational outages, yet the average for the year was the same as 2006 at 33% of WTI. LLB to WTI differentials averaged US$23.83 per barrel in 2007 versus US$22.03 in 2006. The 5-year average Canadian heavy sour crude differential is US$17.89 per barrel (33% of WTI).

In spite of all of the volatility in underlying index, basis and quality price differentials, Baytex's conventional light crude oil and natural gas liquids prices averaged $65.53/bbl before hedging, $11.69/bbl higher than the $53.84 per barrel we received in 2006. This increase, while substantial, was also muted by the impact of the strong Canadian dollar.

In order to manage heavy oil pricing volatility, Baytex has entered into a series of physical sales agreements for delivery of heavy crude in 2008 and 2009. These contracts set the pricing at a fixed differential to WTI and require that Baytex deliver 15,340 barrels per day of LLB or Western Canadian Select ("WCS") heavy crude oil blend for 2008 and 10,340 barrels per day for 2009. Prices received from these contracts average 68% of WTI in 2008 and 67% in 2009.

WTI costless collars have been put in place for 2008 on 6,000 barrels per day at a weighted average price from US$63.33 per barrel to US$79.13 per barrel. No collars have yet been implemented for 2009.

The market and infrastructure solutions for Baytex's Seal area remain a work in progress. Management is confident that long term solutions will be developed to allow accelerated full-scale field development in 2010 and beyond.

Natural Gas

Natural gas prices in North America weakened in 2007, reflecting strong supply availability. Reduced drilling rig activity and falling production in Western Canada was more than offset by activity in the U.S. and a flood of liquified natural gas ("LNG") imports during the summer of 2007. High oil prices sustained gas values at levels that might have been much lower in a lower alternative energy price environment. U.S. inventories were at historically high levels throughout the year. In addition to the new supply from offshore LNG, there was little in the way of any weather related disruptions as suffered during the 2005 hurricane season. U.S. gas prices represented by the NYMEX futures contract, averaged US$6.86/MMBtu in 2007, a decrease of 6% from US$7.27 in 2006. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $6.44/Mcf in 2007, down 1% from $6.51 in 2006. The five-year averages are US$6.85/MMBtu for the NYMEX contract, and $6.97/Mcf for Alberta daily prices.

Baytex received an average of $6.61 per mcf for 2007 natural gas sales compared to $7.13 in 2006, a 7% decrease.

For 2008, Baytex entered into several physical forward natural gas sales contracts with price collars. Contracted volumes total 7.1 MMcf/d during the period from the beginning of January to the end of October for 2008 with an average floor price of $6.65 per Mcf and an average ceiling price of $8.70 per Mcf. An additional series of contracts has been executed, totaling 9.5 MMcf/d for the 2008 calendar year with an average floor price of $6.49 per Mcf and an average ceiling price of $7.63 per Mcf. No price collar or other hedging has been undertaken for 2009.

OPERATIONS

Production

The Trust's average production for fiscal 2007 was 36,222 boe/d compared to 34,292 boe/d for fiscal 2006.

Light oil & NGL production increased by 47% to 5,483 bbl/d from 3,735 bbl/d for last year. Heavy oil production for 2007 increased by 4% to 22,092 bbl/d compared to 21,325 bbl/d in 2006. Natural gas production decreased by 6% to average 51.9 MMcf/d for 2007 compared to 55.4 MMcf/d for 2006. The increase in light oil and NGL volumes was primarily due to the acquisition of the Pembina assets. Heavy oil production increased slightly due to development activities and the acquisition of the Lindbergh assets. The decrease in natural gas production was largely due to natural declines during a year in which Baytex engaged in a very low level of gas development activity due to economic factors.

	Light Oil and NGL *(bbl/d)*	Heavy Oil *(bbl/d)*	Natural Gas *(MMcf/d)*	Oil Equivalent *(boe/d)*
2007				
Heavy Oil District	**–**	**22,092**	**7.3**	**23,315**
Conventional Oil and Gas District	**5,483**	**–**	**44.6**	**12,907**
Total Production	**5,483**	**22,092**	**51.9**	**36,222**
2006				
Heavy Oil District	–	21,325	8.8	22,791
Conventional Oil and Gas District	3,735	–	46.6	11,501
Total Production	3,735	21,325	55.4	34,292

Revenue

Petroleum and natural gas sales for 2007 increased by 11% to $618.9 million from $556.7 million for fiscal 2006. Benchmark WTI crude oil averaged US$72.31 per bbl for 2007, representing a 9% increase over the US$66.22 per bbl for 2006. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$0.9304 in 2007 compared to US$0.8817 in 2006. The Trust's light oil and NGLs price averaged $65.53 per bbl for 2007, representing a 22% increase over the 2006 price of $53.84 per bbl. The heavy oil price increased 2% to $44.28 per bbl in 2007 from $43.57 per bbl in 2006. Natural gas prices were 7% lower in 2007, averaging $6.61 per Mcf compared to $7.13 per Mcf during the previous year. Overall, after accounting for $3.2 million of realized gain on financial derivative contracts, the Trust averaged $46.14 per boe for 2007, a 3% increase from $44.68 per boe received in the prior year.

For 2007, light oil and NGL revenue increased 79% from the same period last year due to a 22% increase in wellhead prices and a 47% in sales volume. Revenue from heavy oil increased 7% due to a 2% increase in wellhead prices and a 5% increase in sales volume. Revenue from natural gas decreased 13% compared to 2006, as production decreased 6% combined with a price decrease of 7%.

Gross Revenue Analysis

	2007		2006	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Oil revenue (bbl)				
Light oil & NGL	131,143	65.53	73,387	53.84
Heavy oil	362,549	44.28	339,066	43.57
Derivative contract gain (loss)	(3,164)	(0.39)	2,529	0.32
Total oil revenue	490,528	48.14	414,982	45.38
Natural gas revenue (Mcf)	125,235	6.61	144,236	7.13
Total revenue (boe)	615,763	46.14	559,218	44.68

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

Royalties

For the year ended December 31, 2007, royalties increased to $102.8 million from $85.0 million for last year. Total royalties in 2007 were 16.6% of sales, compared to 15.3% of sales for 2006. For 2007, royalties were 18.8% of sales for light oil, NGL and natural gas and 15.1% for heavy oil. Roylties are generally based on market index prices realized by the industry in the period, with increasing rates as price and volume escalate. Baytex's increased effective royalty rate for heavy oil in 2007 was reflective of the higher market price.

Operating Expenses

Operating expenses for the year 2007 increased to $134.7 million from $112.4 million in 2006. Operating expenses were $10.09 per boe for 2007 compared to $8.98 per boe for the prior year. In 2007, operating expenses were $9.61 per boe of light oil, NGL and natural gas and $10.40 per barrel of heavy oil compared to $8.58 and $9.23, respectively, for the year earlier.

Transportation Expenses

Transportation expenses for the year ended December 31, 2007 were $28.8 million compared to $24.3 million for 2006. These expenses were $2.16 per boe in 2007 compared to $1.95 in 2006. Transportation expenses were $0.80 per boe of light oil, NGL and natural gas and $3.01 per barrel of heavy oil in 2007, compared to $0.87 and $2.60, respectively, in 2006.

Net Revenue

	Light oil & NGL ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGL ($/bbl)		Natural Gas ($/Mcf)		BOE ($/boe)	
	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Sales price(1)	65.53	53.84	44.28	43.57	48.45	45.10	6.61	7.13	46.38	44.48
Royalties	(12.99)	(7.84)	(6.68)	(6.37)	(7.91)	(6.59)	(1.17)	(1.23)	(7.70)	(6.80)
Operating costs	(10.79)	(11.17)	(10.40)	(9.23)	(10.48)	(9.52)	(1.48)	(1.25)	(10.09)	(8.98)
Transportation	(0.66)	(1.16)	(3.01)	(2.60)	(2.55)	(2.38)	(0.15)	(0.13)	(2.16)	(1.95)
Net revenue	41.09	33.67	24.19	25.37	27.51	26.61	3.81	4.52	26.43	26.75

(1) Sales price is before realized loss/gain recognized on financial derivative contracts, and net of blending costs for heavy oil.

General and Administrative Expenses

General and administrative expenses for 2007 were $23.6 million, compared to $20.8 million for the prior year. On a per sales unit basis, these expenses were $1.77 per boe in 2007 and $1.67 per boe in 2006. The increase is attributable to escalating costs in the labour market and additional expenses associated with increasing regulatory compliance requirements which translated into higher legal, audit, and consulting fees. In accordance with our full cost accounting policy, no expenses were capitalized in either 2007 or 2006.

($ thousands)	2007	2006
Gross corporate expense	32,132	28,538
Operator's recoveries	(8,567)	(7,695)
Net expenses	23,565	20,843

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $8.0 million for 2007 compared to $7.5 million for 2006.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Effective January 1, 2006, the Trust commenced using the binomial-lattice model to calculate the estimated fair value of the unit rights issued.

Interest Expense

In 2007, interest expense was $35.2 million compared to $35.0 million for last year. Interest expense was affected by the recognition of a $2.0 million gain on termination of the interest rate swap associated with the senior subordinated notes, a more favourable exchange rate on the U.S. dollar denominated interest expenses, offset by accretion of the discontinued fair value hedge and higher interest on increased bank borrowings.

Foreign Exchange

The foreign exchange gain for 2007 was $32.5 million compared to $0.1 million in the prior year. The 2007 gain is comprised of an unrealized foreign exchange gain of $32.6 million and a realized foreign exchange loss of $0.1 million. The 2006 gain was substantially unrealized. The 2007 unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 0.8581 at December 31, 2006. The 2006 unrealized gain is based on translation at 0.8581 at December 31, 2006 compared to 0.8577 at December 31, 2005.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $189.5 million for the year ended December 31, 2007 compared to $152.6 million for 2006. On a sales-unit basis, the provision for the current year was $14.20 per boe compared to $12.19 per boe for 2006. The higher rate is due to the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Taxes

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

The government's bill provides that the new regime for income trusts will not apply until January 1, 2011 so long as the Trust experiences only "normal growth" and no "undue expansion". As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40% of that trust's October 31, 2006 market capitalization for the period November 1, 2006 to December 31, 2007, and an additional 20% of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006 / 2007 and $365 million for each of the subsequent three years. Issuance of equity or convertible debt beyond these limits will result in the new regime applying to the Trust before 2011.

Current tax expenses were $6.7 million for 2007 compared to $8.4 million last year. Current tax expense is comprised of $7.2 million of Saskatchewan Capital Tax and Resource Surcharge and a recovery of $0.5 million relating to prior period recoveries. The 2006 current tax expense included $8.2 million of Saskatchewan Capital Tax and Resource Surcharge, a recovery of $0.4 million of Large Corporation Taxes and $0.6 million of prior period adjustments.

The fiscal 2007 provision for future income taxes was a recovery of $49.4 million compared to a recovery of $41.2 million for the prior year. As a result of the Pembina/Lindbergh acquisition, Baytex recognized a future income tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Federal Tax Pools

($ thousands)	2007	2006
Cumulative Canadian Exploration Expense	**36,872**	9,803
Cumulative Canadian Development Expense	**183,910**	124,111
Cumulative Canadian Oil and Gas Property Expense	**187,899**	164,781
Undepreciated Capital Cost	**217,939**	199,504
Other	**19,827**	28,633
Total Canadian federal tax pools	**646,447**	526,832
U.S. Tax Pools	**2,132**	–

Cash Flow from Operations

Cash flow from operations in 2007 increased 4% to $286.0 million from $274.7 million for the previous year. The increase is primarily due to higher production volumes. On a barrel of oil equivalent basis, cash flow from operations was $21.63 for 2007 compared to $21.94 for 2006.

Netback and Cash Flow

	2007		2006	
	$/boe	% of Revenue	$/boe	% of Revenue
Production revenue	46.38	100	44.48	100
Derivative contract gain (loss)	(0.24)	(1)	0.20	–
Royalties	(7.70)	(17)	(6.80)	(15)
Operating expenses	(10.09)	(22)	(8.98)	(20)
Transportation	(2.16)	(5)	(1.95)	(4)
Operating netback	26.19	56	26.95	61
General and administrative expenses	(1.77)	(4)	(1.67)	(4)
Interest expense	(2.38)	(5)	(2.68)	(6)
Current income taxes	(0.50)	(1)	(0.67)	(2)
Cash flow	21.54	46	21.93	49

Net Income

Net income for 2007 was $132.9 million compared to $147.1 million for 2006. The variance was due to higher operating and transportations costs, higher depletion rates, and higher general and administrative costs. These negative factors were partially offset by higher sales volumes and prices and a higher foreign exchange gain.

Capital Expenditures

Capital expenditures during 2007 totaled $394.1 million, with $148.7 million spent on exploration and development activities, $243.3 million on corporate acquisitions and $2.2 million spent on acquisitions net of dispositions of assets. For the year ended December 31, 2007, the Trust participated in the drilling of 136 (127.9 net) wells, resulting in 103 (98.3 net) oil wells, 20 (16.8 net) gas wells, seven (6.8 net) stratigraphic test and service wells and six (6.0 net) dry holes compared to prior year activities of 128 (117.6 net) wells, including 98 (91.3 net) oil wells, 21 (18.1 net) gas wells, three (3.0 net) stratigraphic test wells and six (5.2 net) dry holes.

	Year Ended December 31	
($ thousands)	2007	2006
Land	7,253	11,118
Seismic	1,994	2,202
Drilling and completion	108,106	97,273
Equipment	26,624	19,240
Other	4,742	2,548
Total exploration and development	148,719	132,381
Corporate acquisition (net of working capital)	243,273	–
Property acquisitions	2,877	1,530
Property dispositions	(723)	(828)
Total capital expenditures	394,146	133,083

Liquidity and Capital Resources

At December 31, 2007, total net monetary debt was $444 million compared to $367 million at the end of 2006. The increase is mainly attributable to the bank loan incurred to partially finance the acquisition of the Pembina and Lindbergh properties at the end of the second quarter. Bank borrowings and working capital deficiency at the end of 2007 was $250.1 million compared to total credit facilities of $370 million.

Baytex 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 syndicated credit facilities were increased from $300 million to $370 million during June 2007. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. At December 31, 2007 a total of $241.7 million had been drawn under the credit facilities.

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities. Baytex had entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2% until the maturity of these notes. On November 29, 2007 Baytex terminated the interest rate swap contract. A gain on termination of $2.0 million has been recorded as reduction of interest expense.

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 or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to finance current operations, distributions to the Unitholders and planned capital expenditures for the ensuing 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 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 may be issued at 95% of the "weighted average closing price" from treasury, or acquired on the market at prevailing market prices. For the purposes of the units issued from 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 prices.

Non-controlling Interest

Baytex is authorized to issue an unlimited number of exchangeable shares. Exchangeable shares can be exchanged (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 Baytex for either cash or the issue of trust units. At December 31, 2007, there were 1.6 million exchangeable shares outstanding. During 2007, 7,000 exchangeable shares were exchanged for trust units. The number of trust units issuable upon exchange is based upon the exchange ratio in effect at the exchange 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, 2007 was 1.67915 trust units per exchangeable share (December 31, 2006 – 1.51072 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 exchanged to trust units.

The exchangeable shares of Baytex 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's 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 2007 total cash distributions of $2.16 per unit were declared. The monthly cash distribution in 2006 was increased to $0.18 from $0.15 per unit, an amount maintained since the inception of the Trust in September 2003. The 2008 monthly distribution continues at $0.18 per unit until April 2008 at which time the monthly distribution will be increased to $0.20 per unit.

Cash Flow from Operations, Payout Ratio and Distributions

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

	2007	2006
Cash flow from operating activities	$ 286,450	$ 261,982
Change in non-cash working capital	(5,140)	9,058
Asset retirement expenditures	2,442	1,747
Decrease (increase) in deferred charges and other assets	2,278	1,875
Cash flow from operations	$ 286,030	$ 274,662
Cash Distributions declared	$ 145,927	$ 143,072
Payout ratio	51%	52%

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

Cash distributions of $145.9 million during 2007 were funded through cash flow from operations of $286.0 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	2007	2006
Cash flow from operating activities	$ 286,450	$ 261,982
Actual cash distributions payable	145,927	143,072
Excess of cash flow from operating activities over cash distributions paid	$ 140,523	$ 118,910
Net Income	$ 132,860	$ 147,069
Actual cash distributions payable	145,927	143,072
Excess (shortfall) of net income over cash distributions paid	$ (13,067)	$ 3,997

It is Baytex's long term operating objective to substantially fund cash distributions and capital expenditures required to maintain production and reserves through cash flow from operating activities. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of temporary decline in commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall will be funded through a combination of equity and debt financing. As at December 31, 2007, Baytex had approximately $120 million in available credit facilities to fund such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the year ended December 31, 2007, the Trust's cash distribution exceeded net income by $13.1 million with net income reduced by $153.6 million of non-cash items. Non-cash charges such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

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, 2007

	Payments Due			
($thousands)	Total	Within 1 year	1-3 years	4-5 years
Long-term debt	177,805	–	177,561	244
Interest payable on long-term debt	43,435	17,116	26,319	–
Convertible debentures	16,150	–	16,150	–
Interest payable on convertible debentures	3,241	1,080	2,161	–
Operating leases	5,983	2,459	3,318	206
Transportation agreements	3,505	1,812	1,498	195
Processing obligations	18,859	4,725	9,423	4,711
Total contractual obligations	268,978	27,192	236,430	5,356

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

The Trust also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them 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 Baytex'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 reserves 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 U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. 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 Baytex's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates.

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

A summary of Baytex's significant accounting policies can be found in Notes 1 and 2 to the Consolidated Financial Statements. 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 on a country-by-country cost centre basis. 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 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 reserves estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result in a significant accounting loss for a particular period.

Goodwill

As the result of an acquisition in 2004, goodwill of $37.8 million was recorded based on the excess of total consideration paid less the value assigned to the identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is charged to income in the period in which it occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2007.

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.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

Baytex is subject to corporate income taxes and follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using substantially enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan ("The Plan") is described in note 12 to the Consolidated Financial Statements. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

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.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855 "Financial Instruments – Recognition and Measurement", section 3865 "Hedges", section 1530 "Comprehensive Income" and section 3861 "Financial Instruments – Disclosure and Presentation". These standards have been adopted retrospectively. See Note 3 to the Consolidated Financial Statements for further detail and the impact on the Trust's financial statements from application of these new standards.

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

NEW ACCOUNTING PRONOUNCEMENTS

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Section 3862, Financial instruments – Disclosures, and Section 3863, Financial instruments – Presentation. These new standards will be effective on January 1, 2008.

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

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks. This Section is expected to have minimal impact on the Trust's financial statements.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, which replaces Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new Section to have a material impact on its consolidated financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRSs"). In March 2007, the AcSB released an "Implementation Plan for Incorporating IFRSs into Canadian GAAP", which assumes a convergence date of January 1, 2011. Following a progress review on February 13, 2008, the AcSB has confirmed this changeover date. The Trust continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

FOURTH QUARTER 2007

The following discussion reviews the Trust's results of operations for the fourth quarter of 2007.

Production

Light oil and NGL production for the fourth quarter of 2007 increased by 123% to 8,123 bbl/d from 3,643 bbl/d a year earlier primarily as a result of the acquisition of the Pembina assets near the end of the second quarter of 2007. Heavy oil production was little changed from year-ago levels, averaging 22,196 bbl/d for the fourth quarter of 2007 compared to 22,416 bbl/d a year ago. Natural gas production increased by 5% to 53.9 MMcf/d for the fourth quarter of 2007 compared to 51.4 MMcf/d for the same period last year. The increase was primarily the result of the Pembina acquisition offsetting natural declines during a quarter in which Baytex engaged in a very low level of gas development activity due to economic factors.

Revenue

Petroleum and natural gas sales decreased 47% to $197.4 million for the fourth quarter of 2007 from $134.5 million for the same period in 2006. Revenue from light oil and NGL for the fourth quarter of 2007 increased 243% from the same period a year ago due to a 123% increases in sales volume and a 54% increase in wellhead prices. Revenue from heavy oil increased 30% as the result of a 22% increase in wellhead prices in addition to a 7% increase in sales volume. Revenue from natural gas decreased 6% as the result of a 5% increase in volume offset by a 10% decrease in wellhead prices.

Royalties

Total royalties increased to $32.5 million for the fourth quarter of 2007 from $18.5 million in 2006. Total royalties for the fourth quarter of 2007 were 16.5% of sales compared to 13.8% of sales for the same period in 2006. For the fourth quarter of 2007, royalties were 19.9% of sales for light oil, NGL and natural gas, and 13.7% for heavy oil. These rates compared to 16.6% and 12.1%, respectively, for the same period last year. Royalties are generally based on market index prices realized by the industry in the period, with rates increasing as price and volume escalate.

Operating Expenses

Operating expenses for the fourth quarter of 2007 increased to $38.7 million from $29.8 million in the corresponding quarter last year. Operating expenses were $10.25 per boe for the fourth quarter of 2007 compared to $9.36 per boe for the fourth quarter of 2006. For the fourth quarter of 2007, operating expenses were $9.67 per boe of light oil, NGL and natural gas, and $10.66 per barrel of heavy oil. The operating expenses for the same period a year ago were $9.15 and $9.47, respectively. The increase in operating costs for conventional oil and gas was in part due to the addition of higher cost sour operations at Pembina. In general, the inflationary environment affecting operating costs has not entirely subsided as certain cost categories such as property taxes, labour costs and fuel costs continued to increase. This is particularly prevalent in heavy oil operating areas as industry activity levels remain strong due to robust economics associated with the current heavy oil pricing environment.

Transportation Expenses

Transportation expenses for the fourth quarter of 2007 were $7.5 million compared to $6.4 million for the fourth quarter of 2006. These expenses were $1.98 per boe for the fourth quarter of 2007 compared to $2.00 for the same period in 2006. Transportation expenses were $0.67 per boe of light oil, NGL and natural gas and $2.92 per barrel of heavy oil. The corresponding amounts for fourth quarter of 2006 were $0.82 and $2.64, respectively.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2007 increased to $6.8 million from $5.9 million a year earlier. On a per sales unit basis, these expenses were $1.81 per boe for the fourth quarter of 2007 compared to $1.84 per boe for the same period in 2006. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2007 compared to $2.2 million for the fourth quarter of 2006.

Interest Expense

Interest expense for the fourth quarter of 2007 remained consistent at $8.7 million compared to the same quarter last year. Interest expense was affected by the recognition of a $2.0 million gain on the termination of the interest rate swap associated with the senior subordinated notes, a more favourable exchange rate on the U.S. dollar denominated interest expenses, offset by accretion of the discontinued fair value hedge and higher interest on increased bank borrowings.

Foreign Exchange

Foreign exchange gain in the fourth quarter of 2007 was $1.3 million compared to a loss of $9.0 million in the fourth quarter of 2006. The 2007 amount is comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.2 million. The loss in the 2006 period was entirely unrealized. The current quarter's unrealized gain is based on the translation of the U.S. dollar denominated long-term debt at 1.0120 at December 31, 2007 compared to 1.0037 at September 30, 2007. The prior period loss is based on translation at 0.8581 at December 31, 2006 compared to 0.8966 at September 30, 2006.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion for the fourth quarter of 2007 increased to $54.1 million from $39.5 million for the same quarter in 2006. On a sales-unit basis, the provision for the current quarter was $14.33 per boe compared to $12.38 per boe for the same quarter in 2006. The higher rate is due to the higher per unit cost of the proved reserves acquired at the end of the second quarter of 2007, as well as the resulting accounting adjustments for future income taxes and asset retirement obligations.

Net Income

Net income for the fourth quarter of 2007 was $41.4 million compared to $20.0 million for the fourth quarter in 2006. The variance was the result of higher production, higher sales prices, foreign exchange gains and future income tax recovery, offset by higher operating costs.

Trust Unit Information

At February 29, 2008, the Trust had 85,485,500 units outstanding and Baytex had 1,563,440 exchangeable shares outstanding. The exchange ratio at February 29, 2008 was 1.71212 trust units per exchangeable share.

At February 29, 2008, the Trust had $16.2 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

($ thousands, except per unit amounts)	2007	2006	2005
Financial			
Revenue	**618,927**	556,689	546,940
Net income(1)	**132,860**	147,069	79,876
Per unit basic(1)	**1.66**	2.02	1.19
Per unit diluted(1)	**1.60**	1.91	1.15
Total assets	**1,407,150**	1,079,629	1,105,567
Total long-term financial liabilities	**190,004**	228,597	283,565
Cash distributions declared per unit	**2.16**	2.16	1.80

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2007 was 36,222 boe per day which represented a 6% increase from 34,292 boe per day in 2006. Average wellhead prices received during 2007 were $46.38 per boe compared to $44.48 during 2006. Production in 2005 was 35,177 boe per day. Average wellhead prices received in 2005 were $42.60 per boe.

Quarterly Information

($ thousands, except per unit amounts)	2007 TOTAL 2007	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 TOTAL 2006	2006 Q4	2006 Q3	2006 Q2	2006 Q1
Revenue	618,927	197,438	164,228	127,511	129,750	556,689	134,541	145,754	140,163	136,231
Cash distributions declared per unit	2.16	0.54	0.54	0.54	0.54	2.16	0.54	0.54	0.54	0.54

Reconciliation of Net Income to Cash Flow from Operations:

Financial

($ thousands, except per unit amounts)	2007 TOTAL 2007	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 TOTAL 2006	2006 Q4	2006 Q3	2006 Q2	2006 Q1
Net income(1)	$ 132,860	$ 41,353	$ 36,674	$ 31,050	$ 23,783	$ 147,069	$ 19,988	$ 42,040	$ 56,162	$ 28,879
Items not affecting cash:										
Unit based compensation	7,986	1,810	2,370	1,946	1,860	7,460	2,168	1,740	1,821	1,731
Amortization of deferred charges	–	–	–	–	–	1,267	304	314	200	449
Unrealized foreign exchange loss (gain)	(32,574)	(1,526)	(12,263)	(16,495)	(2,290)	(108)	8,997	54	(9,375)	216
Depletion, depreciation and accretion	189,512	54,086	51,525	42,541	41,360	152,579	39,488	38,285	36,639	38,167
Accretion on debentures & notes	2,164	2,059	35	34	36	189	33	42	31	83
Unrealized loss (gain) on financial derivatives	31,320	27,264	(599)	4,005	650	2,790	408	(11,762)	7,527	6,617
Future income taxes (recovery)	(49,369)	(27,659)	(3,895)	(11,307)	(6,508)	(41,169)	(10,167)	332	(24,742)	(6,592)
Non-controlling interest	4,131	1,280	1,110	981	760	4,585	2,300	885	1,202	198
Cash flow from operations(2)	$ 286,030	$ 98,667	$ 74,957	$ 52,755	$ 59,651	$ 274,662	$ 63,519	$ 71,930	$ 69,465	$ 69,748
Change in non-cash working capital	5,140	3,145	(308)	956	1,347	(9,058)	(1,913)	7,608	(15,667)	914
Asset retirement expenditures	(2,442)	(1,131)	(351)	(257)	(703)	(1,747)	(233)	(361)	(746)	(407)
Decrease in deferred charges and other assets	(2,278)	(550)	(576)	(576)	(576)	(1,875)	(409)	(488)	(489)	(489)
Cash flow from operating activities	$ 286,450	$ 100,131	$ 73,722	$ 52,878	$ 59,719	$ 261,982	$ 60,964	$ 78,689	$ 52,563	$ 69,766
Net income per unit(1)										
Basic	1.66	0.49	0.44	0.41	0.32	2.02	0.27	0.57	0.77	0.41
Diluted	1.60	0.48	0.43	0.39	0.30	1.91	0.26	0.54	0.73	0.39
Cash flow from operations per unit(2)										
Basic	3.57	1.17	0.90	0.69	0.79	3.77	0.85	0.98	0.96	0.99
Diluted	3.54	1.10	0.84	0.65	0.74	3.45	0.79	0.90	0.88	0.90
Cash flow from operating activities per unit										
Basic	3.58	1.19	0.88	0.69	0.79	3.59	0.81	1.07	0.72	0.99
Diluted	3.33	1.11	0.83	0.64	0.74	3.26	0.78	0.98	0.66	0.90

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

(2) 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.

	2007					2006				
	TOTAL 2007	Q4	Q3	Q2	Q1	TOTAL 2006	Q4	Q3	Q2	Q1
Production										
Light oil and NGLs *(bbl/d)*	5,483	8,123	6,556	3,705	3,484	3,735	3,643	3,594	3,619	4,089
Heavy oil *(bbl/d)*	22,092	22,196	22,593	21,444	22,129	21,325	22,416	21,325	20,413	21,134
Total oil and NGL *(bbl/d)*	27,575	30,319	29,149	25,149	25,613	25,060	26,059	24,919	24,032	25,223
Natural gas *(MMcf/d)*	51.9	53.9	53.7	49.3	50.6	55.4	51.4	54.9	54.7	60.6
Oil equivalent *(boe/d)*	36,222	39,304	38,094	33,372	34,041	34,292	34,631	34,074	33,154	35,319

	2007					2006				
	TOTAL 2007	Q4	Q3	Q2	Q1	TOTAL 2006	Q4	Q3	Q2	Q1
Average Prices										
WTI oil *(US$/bbl)*	72.31	90.68	75.38	65.03	58.27	66.22	60.21	70.48	70.70	63.48
Edmonton par oil *($/bbl)*	76.35	86.41	80.24	72.15	67.09	72.77	64.49	79.17	78.61	68.99
BTE light oil *($/bbl)*	65.53	74.77	67.82	54.42	51.08	53.84	48.62	57.94	57.83	51.33
BTE heavy oil *($/bbl)*	44.28	50.13	45.89	40.14	40.17	43.57	41.15	48.28	47.10	37.87
BTE total oil *($/bbl)*	48.45	56.37	50.85	42.26	41.66	45.10	42.19	49.68	48.71	40.05
BTE natural gas *($Mcf)*	6.61	6.31	5.80	7.02	7.43	7.13	7.03	6.35	6.68	8.36
BTE oil equivalent *($/boe)*	46.38	52.32	47.06	42.22	42.38	44.48	42.19	46.57	46.35	42.94

2008 Guidance

Baytex has set a 2008 capital budget of $150 million designed to maintain our production levels at an annual average between 37,000 boe/d and 38,000 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 94 gross wells, including 15 to 20 primary horizontal producers in our Seal area in the Peace River oil sands region. The remainder of this budget has been allocated to our conventional oil and gas operations, including the drilling of 30 gross wells. Our 2008 production mix is forecast to be approximately 60% heavy oil, 18% light oil and NGL and 22% natural gas. During the first half of 2008, we plan to commence our thermal cyclic steam pilot project at Seal, where success could provide a material positive impact on Baytex's future heavy oil production and reserves. We will have a full year's benefit from the Pembina and Lindbergh assets acquired mid-year 2007. We also plan to proactively establish our operations in the United States to add to our investment and growth opportunities and to enhance the geographic diversity of our asset portfolio.

Baytex has entered into the following contracts to provide downside protection to 2008 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

OIL

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

Foreign Currency

	Period	Amount	Rate
Swap	January 1, 2008 to June 30, 2008	US$ 10,000,000 per month	CAD/US$ 0.9935

Physical Sale Contracts

HEAVY OIL

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

GAS

	Period	Volume	Price
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.60
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 9.00
Price collar	January 1 to March 31, 2008	2,500 GJ/d	$ 6.65 – $ 8.05
Price collar	April 1, 2008 to October 31, 2008	5,000 GJ/d	$ 6.15 – $ 7.50
Price collar	April 1, 2008 to October 31, 2008	2,500 GJ/d	$ 6.15 – $ 9.35
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.00
Price collar	Calendar 2008	5,000 GJ/d	$ 6.15 – $ 7.46

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, 2007 consolidated financial statements for description of accounting treatment of these derivative contracts.

Environmental Regulation and Risk

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

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

Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

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

The Federal Government and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

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

The New Royalty Framework

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

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

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

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

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed.

As previously reported, we had requested that our reserves evaluator, Sproule, estimate the impact to our reserves evaluation based upon the currently released information on the new royalty regime. As of December 31, 2007, the province had not introduced the enabling legislation nor had they provided enough clarity on a number of issues for Sproule to provide a precise calculation of reserves and net present value under the new regime. It is possible that the announced changes may be amended before coming into force. Under the forecast price assumptions, Sproule has estimated that the change to the net present value, discounted at 10%, of future net revenue from our proved plus probable reserves would be a reduction, estimated to be in range of 1.8% to 2.1%.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the specified investment flow-through ("SIFT") tax rate to 28% as compared to the rate of 31.5% previously announced subject to comments below concerning the provincial SIFT tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law trust taxation that will result in a tax of 29.5% (previously 31.5% as discussed above) on all trust distributions commencing January 1, 2011 (28% commencing January 1, 2012). Cash flow earned by the trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the trust tax legislation. As part of the announcement the Minister indicated that the federal government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequence to investors or the trusts.

Currently, the SIFT Rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined SIFT tax rate of 29.5% in 2011. On February 26, 2008, the Minister of Finance announced (the "Provincial SIFT Tax Proposal") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust's taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, the Trust would likely be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2007, an internal evaluation was conducted of the effectiveness of the Trust's disclosure controls and procedures as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 (the "Exchange Act') and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act or under Canadian securities legislation is accumulated and communicated to the Trust's management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

Internal Control over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Management has assessed the effectiveness of the Trust's internal control over financial reporting as defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934 and as defined in Canada by Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2007. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2007 has been audited by Deloitte & Touche LLP, as reflected in their report for 2007. No changes were made to our internal control over financial reporting during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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