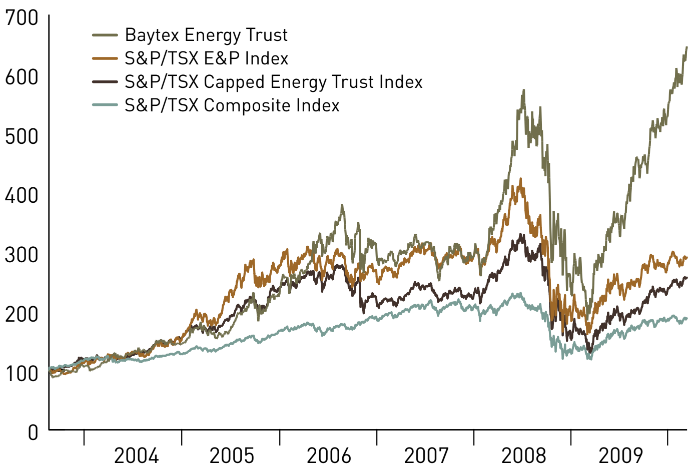
BAYTEX
ENERGY TRUST

Corporate Profile
2009

Contents

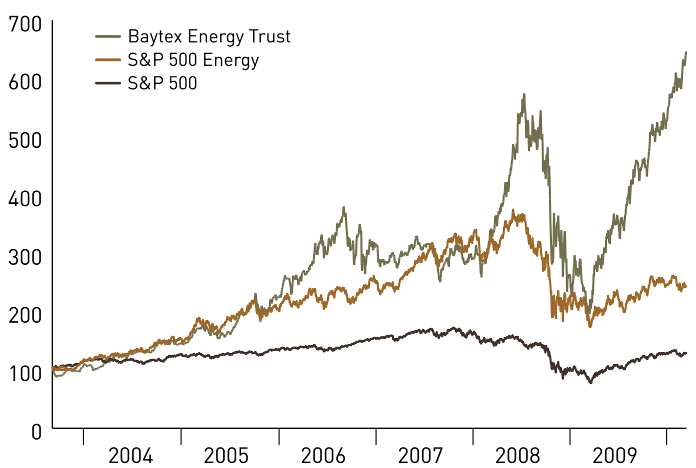
Baytex Energy Trust is a Calgary, Alberta based oil and gas trust engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. The trust also has an emerging presence in the United States. With changes to trust taxation laws in Canada set to take effect January 1, 2011, Baytex's current plan is to convert to a corporation, executing a growth-and-income model, by the end of 2010. Baytex is committed to maintaining its production and asset base through internal property development and delivering consistent returns to its unitholders. Trust units of Baytex are traded on the Toronto Stock Exchange under the symbol BTE.UN and on the New York Stock Exchange under the symbol BTE.

Baytex Total Return vs. Canadian Indices



Source: BMO Capital Markets, Bloomberg

Baytex Total Return vs. U.S. Indices



Source: BMO Capital Markets, Bloomberg

FINANCIAL ADVISORY: In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements contained in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: our plans to convert our legal structure from a trust to a corporation and the timing of such conversion; our average production rate for 2010; our reserves life index; our ability to grow our reserve base and add to production levels through exploration and development activities; petroleum and natural gas prices and differentials between light, medium and heavy oil prices; our cash payout ratio for 2010; our liquidity and financial capacity; our business model and dividend policy following our conversion to a corporation; our 2010 capital budget; our ability to fund our capital budget and cash distributions with funds from operations in 2010; drilling and operational plans for 2010; our Seal heavy oil resource play, including resource potential, our ability to improve production rates, recovery rates and capital efficiencies through enhanced completion techniques, finding and development costs, production efficiencies, our plans to install a commercial thermally-enhanced oil recovery project and the timing thereof, our assessment of the cyclic steam stimulation pilot project, steam-oil ratios, drilling and completion costs per well, initial production rates, estimated ultimate recoverable reserves and recovery factors; our Bakken/Three Forks, Viking and Pembina Cardium light oil resources plays, including resource potential, the number of potential drilling locations and initial production rates; our net asset value per trust unit (before income tax); the value of our undeveloped land holdings; and the amount of future asset retirement obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in petroleum and natural gas prices; variations in interest rates and foreign exchange rates; uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with our conversion to a corporate structure; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; the timing of payment of distributions, if any; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; risks associated with residency restrictions in the ownership of our Trust Units; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the application of accounting policies; the activities of our operating entities and their key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonality; our permitted investments; risks associated with our structure and ownership of Trust Units; risks for United States and other non-resident unitholders and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

All dollar amounts are in Canadian dollars unless otherwise denoted

Front cover: Baytex heavy oil battery at Celtic, in the Lloydminster area of Saskatchewan

Message to Unitholders

We are pleased to report our 2009 results to our unitholders. In 2009, we achieved record levels of production and reserves, as well as our second best year of funds from operations. Operationally, we continued to advance several key projects that should provide reliable and diversified growth in the coming years. We also recorded another year in which we replaced more than 100% of our annual production with reserves developed by our organic exploration and development ("E&D") investment activities. Finally, our balance sheet continued to improve, maintaining our financial position as one of the strongest in our sector. We were also fortunate to deliver the strongest total market return performance among our peer group in 2009. This market recognition leaves us honoured, and also determined to continue to focus on delivering sustainable income and growth to our unitholders.

OPERATIONS REVIEW

Production averaged 42,713 boe/d in the fourth quarter of 2009, and 41,382 boe/d for the full year, a 3% increase over 2008. With respect to product mix, Baytex is one of the most oil-weighted entities in the North American energy industry, with 80% of our production and 89% of our reserves represented by heavy and light oil.

Our 2009 capital expenditures ("CAPEX") were reduced from 2008 levels, in both aggregate terms and also for each of E&D and acquisition expenditures. Spending for E&D totaled $157 million, with the majority directed toward heavy oil projects. During the year, Baytex participated in the drilling of 113 gross (99.0 net) wells on our heavy oil, light oil and natural gas properties, generating a 96% success rate.

Our total capital program for 2009, including acquisitions, amounted to $290 million. This CAPEX program allowed Baytex to increase its reserve base in both proved and probable reserve categories for the sixth consecutive year, encompassing our entire history as an energy trust. At year-end 2009, our proved plus probable reserves, as evaluated by Sproule Associates Limited, reached 197 million boe. This reserve total represents a 12.4 year reserve life index at our expected production rate of 43,500 boe/d for 2010.

Baytex continued to record strong CAPEX efficiencies in 2009. Finding, development and acquisition ("FD&A") costs were $11.63/boe on a proved plus probable basis (excluding future development capital), resulting in a recycle ratio of 2.4. Our strong capital efficiency is further demonstrated by replacement of 113% of the year's production through E&D, while reinvesting only 47% of funds from operations ("FFO") into E&D activities. Including acquisitions, we replaced 165% of our 2009 production. These results are consistent with our long-term performance in capital efficiency. Our five-year average FD&A cost of $9.72/boe, recycle ratio of 2.8 and reserve replacement ratio of 214% all rank among the best in our industry.

At Seal in the Peace River oil sands region, we drilled 17 new cold horizontal producers, continuing our record of 100% drilling success and increasing production from this important growth property to 7,000 bbl/d by the end of 2009. We advanced our use of multi-lateral horizontal wells at Seal to increase production rates and recoveries, and to further improve our capital efficiencies. We continue to work toward installation of our first commercial thermally-enhanced oil recovery project at Seal, planned for late 2011.

Production increased from our Lloydminster core heavy oil area through new drilling, recompletion of existing wells and an asset acquisition. In the third quarter, we acquired predominantly heavy oil properties in Kerrobert at the southern end of the Lloydminster area. These properties, purchased for $86 million, currently produce approximately 2,800 boe/d. We have identified a number of opportunities to expand both cold production and steam assisted gravity drainage ("SAGD") operations on the acquired lands, and expect to invest in these opportunities over the next few years.

We continued to pursue several light oil growth projects of long-term importance. The Bakken-Three Forks play in North Dakota and the Viking play in Alberta and Saskatchewan utilize horizontal wells, most often with multiple hydraulic fracture stimulations, to induce light oil production from low permeability reservoirs. These plays contain very large volumes of light oil resource in place and have the potential, over time, to generate significant increases in Baytex's light oil production and reserves. We assembled these new light oil resource plays with three objectives in mind: value accretion to our unitholders, enhancement of our overall growth rate and diversification of our long-term product and project mix. These light oil resource plays will complement the growth of our heavy oil projects at Seal and Lloydminster.

In the fourth quarter of 2009, we completed our deferred acquisition payments for the Bakken-Three Forks land that we added to our portfolio during 2008. We drilled and completed our first operated wells in this play, achieving a 100% success rate and recording initial production rates of approximately 300 bbl/d per well. Drilling activity will continue at an increased pace in 2010.

In our Viking play in Alberta, we drilled three successful multi-lateral horizontal wells (without hydraulic fracturing) with an average initial production rate in excess of 130 bbl/d per well. During 2010, we plan to continue with this type of development activity in the Viking in Alberta, as well as use single-lateral horizontal wells with multi-stage hydraulic fracturing in our Viking project in Saskatchewan.

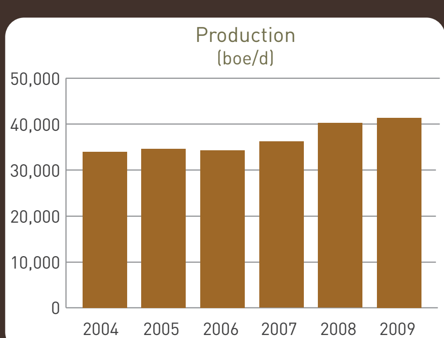
FINANCIAL REVIEW

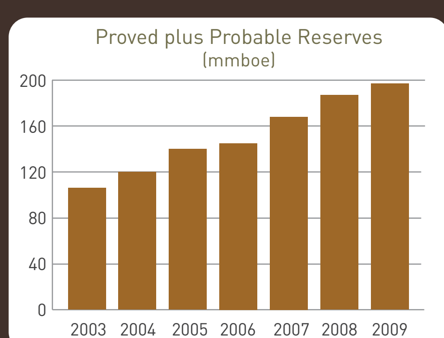
We are encouraged by our operating results and CAPEX efficiencies, and it is through these measures that we seek to differentiate ourselves from our competitors. Our success in these areas helped us post strong financial results despite significantly lower commodity prices as compared to 2008.

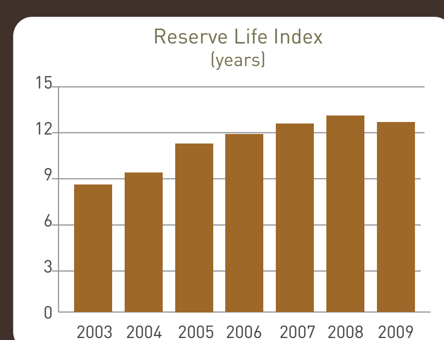
West Texas Intermediate ("WTI") oil price for 2009 averaged US$61.80/bbl, a decrease of 38% from the average for 2008. However, this average price does not fully illustrate the extraordinary volatility in oil prices over the course of 2009. As the economic crisis deepened and the world economy contracted, WTI bottomed at US$32.70/bbl in January 2009. With the easing of the systemic financial crisis and signs of economic recovery, WTI recovered to a peak of US$82.00/bbl in October 2009.

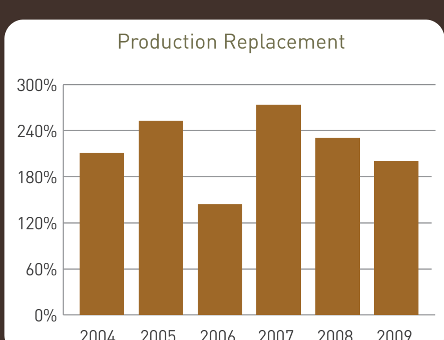
Because WTI prices are denominated in U.S. dollars, a strengthening Canadian currency partially reduced the positive impact of the oil price recovery for Canadian producers. The Canadian dollar, which began 2009 at US$0.82 following the worldwide flight to U.S. dollars during the initial stages of the financial crisis, rose to

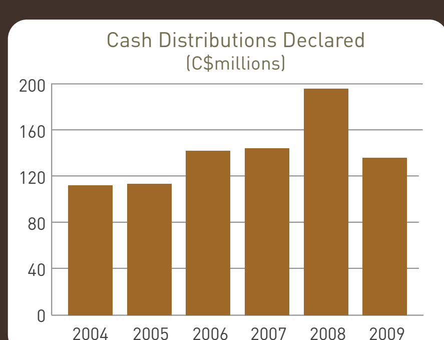
BAYTEX RECORD SINCE TRUST INCEPTION

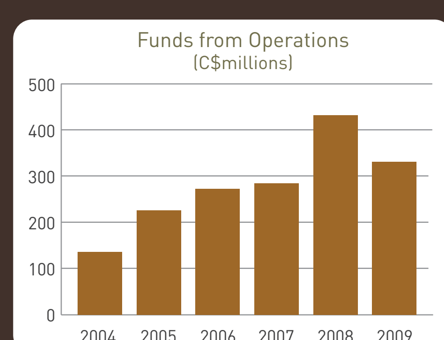








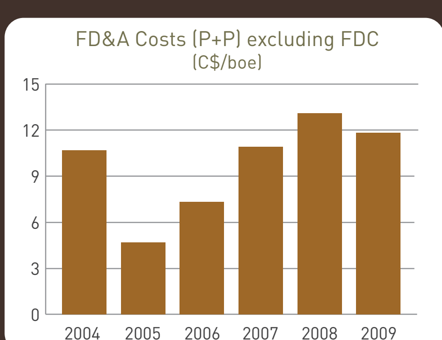


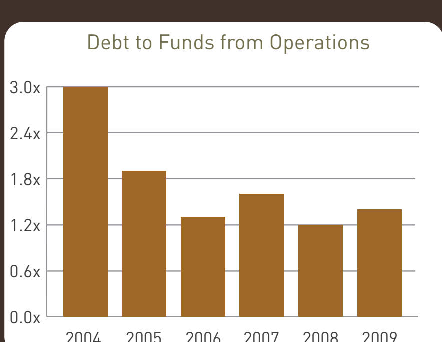


US$0.96 by the end of 2009. In late 2008, we were of the view that the Canadian currency was likely to strengthen versus the U.S. dollar, and put in place currency hedges to protect about 33% of our foreign exchange exposure for 2009, thereby reducing the impact of the stronger Canadian dollar on our 2009 cash flow.

We are fortunate to be particularly weighted to heavy oil, which has benefitted from a narrowing of differentials and reduced volatility as compared to WTI. The heavy blend benchmark, Western Canadian Select ("WCS"), sold at a 16% discount to WTI during 2009 as compared to a 22% discount during 2008. In the first quarter of 2010, differentials for WCS are averaging approximately 12% of the WTI price, resulting in wellhead prices for heavy oil that are yielding very high rates of return on our investment program. The improvement in heavy oil differentials is the result of a number of North American and global supply/demand factors: increased demand from refineries in both North America and Asia that have been reconfigured to process more heavy oil, reduced output of heavy oil by traditional suppliers such as Mexico, and increased pipeline capacity to U.S. markets.

Natural gas prices followed a similar, albeit less pronounced, trajectory as crude oil. After beginning 2009 at $5.79/mcf and bottoming at $2.76/mcf in August, AECO spot prices recovered to $5.51/mcf by the end of the year due to a relatively cold and early winter in much of North America. With only 14% of revenue coming from natural gas in 2009, the fluctuations in natural gas prices had a minor impact on our cash flow.





Operating expenses decreased as costs for fuel and oilfield services declined due to the recession and the commodity price retracement. For 2009, our operating expense averaged $10.83/boe, a 7% decrease from the previous year. Transportation expense increased by 14% to $3.22/boe due to higher production from Seal, which requires long-haul trucking. Exclusive of non-recurring compensation expense related to U.S. tax treatment of our trust unit rights incentive plan, general and administrative expense ("G&A") expenses increased 5% to $2.09/boe. We do not capitalize any G&A costs, and our G&A expense has consistently been below sector averages.

FFO for 2009 was our second-best ever at $332 million, a decrease of 23% from 2008's record level which was generated during a period of much higher commodity prices. FFO increased each quarter during 2009, from a low of $59 million in the first quarter to a high of $97 million in the fourth quarter.

In response to the rapid descent of commodity prices in late 2008 and early 2009, we reduced our monthly distribution rate from $0.18 per unit to $0.12 per unit in February 2009 to adjust cash outflows to inflows and to preserve liquidity. As a result of the oil price recovery and our strong operating results, we restored the distribution level to $0.18 per unit in December 2009. Cash distributions for 2009 were $138 million, bringing our cumulative cash distributions to more than $1 billion since trust inception.

Our payout ratio for 2009 averaged 41%, net of participation in our distribution reinvestment program ("DRIP"). Importantly, we were able to fund 100% of our E&D CAPEX and cash distributions from FFO, which we consider a key measure of the sustainability of our growth-and-income model. At our current monthly distribution of $0.18 per unit, our cash payout ratio (net of DRIP) is forecast to be about 40% for 2010, based on the current commodity price strip.

Total monetary debt at year-end 2009 was $474 million. This debt level corresponds to 1.2 times annualized FFO for the fourth quarter of 2009. In August 2009, we placed a $150 million issue of 9.15% seven-year senior unsecured debentures in the Canadian non-investment grade bond market, the first of its type by an energy issuer in this nascent debt market. Our notes issue was well-received, and with subsequent reductions in credit spreads, currently trades at approximately a 7% yield. In September 2009, we retired US$180 million of senior subordinated notes which were scheduled to mature in July 2010. Our new Canadian issue and our history as an issuer in the U.S. bond market illustrate our capability to access the debt markets should we have a need for external financing.

Most of our debt is represented by drawings on our reserve-based revolving credit facilities, which are provided by a syndicate of eight banks from Canada, the U.S. and Europe. At year-end 2009, our undrawn credit facilities were $198 million, providing us significant liquidity. We are also pleased to note that our banking syndicate increased our credit facilities by 6% at mid-year 2009, making us one of very few North American energy entities to receive an increase in banking facilities in a credit-constrained environment.

OUTLOOK

One year ago, we faced a deepening global recession, a commodity price collapse and a credit contraction all at the same time. Consequently, we took the prudent steps to maintain our sustainability by reducing our distribution and our 2009 CAPEX program from its originally-planned level. Although we made adjustments in response to the financial crisis, we also continued to focus on our long-term strategy to add real value to Baytex.

In this very capital-intensive business, we maintained our investment efficiency. We ensured operational sustainability by continuing to expand our heavy oil and light oil project inventory. We diversified our sources of capital with our Canadian debt offering. We increased our financial flexibility by achieving increased banking facilities in a difficult credit environment. Most importantly, we strengthened our organization in a number of key areas, including thermal operations, exploration, risk management, long-range planning, legal, financial reporting and investor relations.

The market rewarded Baytex with a sector-leading total return of 121% during 2009, including both appreciation of our unit price and reinvestment of distributions. Our total return since inception of the trust to the end of February 2010 has been 546%, significantly higher than the 157% return of the S&P/TSX Capped Energy Trust Index over the same period.

January 1, 2011 marks the implementation of the Tax Fairness Plan announced by the Canadian federal government in 2006. In 2010, we are transitioning to a growth-and-income model, presaging our planned conversion to a corporation prior to the beginning of 2011. Under the new corporate structure, we expect to maintain a significant dividend payout while placing more emphasis on growth than in the income trust era. Our planned 2010 capital budget of $235 million for E&D is designed to generate average production of 43,500 boe/d during 2010, a 5% increase over 2009. Based on the current commodity price strip, we are projecting that FFO in 2010 will be sufficient to fully fund our budgeted E&D CAPEX and cash distributions.

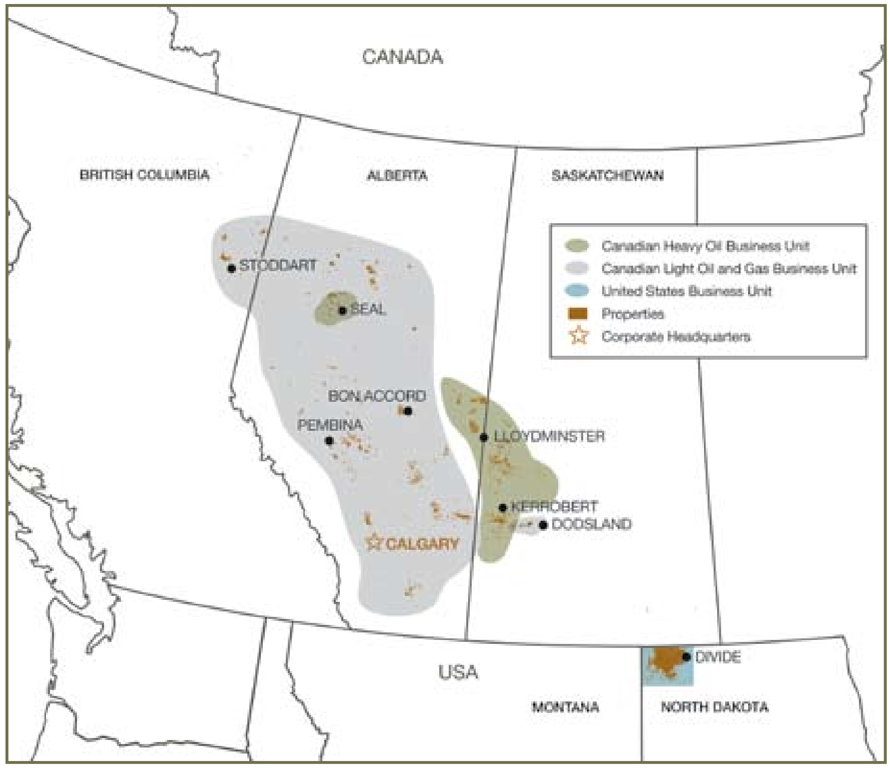
In the new corporate era, as in the trust era, we will base our business on sound technical decisions, prudent financial practices and the creation of real value from our assets. I would venture to say that the emphasis on capital efficiency that Baytex learned during the trust era should prepare us well for the coming corporate era. I can assure you that Baytex's management and staff, led by our Board of Directors, will continue to work hard on behalf of our unitholders as we make the transition to a corporation. It remains an honour to serve you, and we want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

Anthony Marino
President and Chief Executive Officer
March 15, 2010

Baytex Properties

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Light Oil and Gas, and United States Business Units. Each Business Unit has an extensive portfolio of operated properties and development prospects. Within these Business Units, Baytex has established a total of eight geographically-organized teams, each with a full complement of technical professionals including engineers, geoscientists and landmen. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of these opportunities.



Canadian Heavy Oil Business Unit – The cornerstone of Baytex is our heavy oil operation. The Canadian Heavy Oil Business Unit accounts for more than 60% of current production and more than 70% of oil-equivalent reserves. Baytex's heavy oil operations consist primarily of cold primary production, but in some cases waterflooding and thermal operations are employed. Key properties include the Lloydminster region of west central Saskatchewan, Kerrobert in southwest Saskatchewan, which includes a Steam Assisted Gravity Drainage ("SAGD") project, and Seal in northwest Alberta, where Baytex has successfully tested Cyclical Steam Stimulation ("CSS") in addition to cold primary production. In 2009, production in the Canadian Heavy Oil Business Unit averaged approximately 25,900 boe/d (95% crude oil). We drilled 90 gross (82.3 net) wells in 2009 with a resulting success rate of 97%. Our net undeveloped land position totals 382,000 acres.

Canadian Light Oil & Gas Business Unit – Although Baytex is best known as a "heavy oil" company, we also possess a growing array of light oil and natural gas properties. The geographic scope of our Canadian light oil and gas operations spans Alberta, southwest Saskatchewan and northeast British Columbia. The Conventional Light Oil and Gas Business Unit accounts for approximately 33% of current production and about 20% of oil-equivalent reserves. Emerging light oil resource plays within our portfolio include the Viking at both Bon Accord in southeast Alberta and Dodsland in southwest Saskatchewan, as well as Cardium development at Pembina in central Alberta. During 2009, we drilled 16 gross (14.5 net) wells at a 94% success rate. Our net undeveloped land positions totals 289,000 net acres at year-end 2009.

United States Business Unit – We first acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. At year-end 2009, our net undeveloped acreage position totaled 126,000 acres. Our largest property in the United States Business Unit is our Bakken-Three Forks project in North Dakota. We also hold lands in several other U.S. states. In 2009, we participated in the drilling of 7 gross (2.2 net) wells for a success rate of 100%.

Focus on Seal

A Highly Prospective Property. No property better exemplifies Baytex's future growth potential than Seal, located in the Peace River oil sands area of northwest Alberta. Since the beginning of 2000, we have accumulated 105 sections of 100% working interest lands, grown production from zero to a current rate in excess of 7,000 bbl/d and at year-end 2009, our proved plus probable reserves totaled 55 mmboe. Production at Seal in 2009 averaged 5,100 bbl/d, up 38% versus a 2008 average production rate of 3,700 bbl/d. Through year-end 2009, we have drilled 61 oil wells with a 100% success rate. The estimated resource potential of our prospective lands at Seal is 50 million barrels of original oil in place ("OOIP") per section. The vast resource base, combined with the exceptional capital and production efficiencies Baytex has achieved, offers significant upside potential, making Seal one of our main areas of development focus going forward.

SEAL – OPERATING STATISTICS

Land position	105 sections
Average working interest	100%
Average production rate - 2009	5,100 bbl/d
2009 exit production rate	7,000 bbl/d
Proved plus probable reserves (YE 2009)	55 mmboe
Producer wells drilled to December 2009	61
Stratigraphic wells drilled to December 2009	26
Drilling success rate	100%

SEAL – RESERVOIR CHARACTERISTICS

Average pay thickness	15 - 20 metres
Average porosity	28%
Permeability	0.5 – 5.0 darcies
Depth	600 - 700 metres
Oil quality	11 °API

BAYTEX SEAL TIMELINE

2001 - 2004

- Acquired 96 sections of 100% owned and operated land
- Completed geological and geophysical work and identified drilling locations
- Drilled nine stratigraphic test wells

2005

- Added additional lands at Seal
- Drilled four stratigraphic test wells and six horizontal producing wells
- Production averaged 500 bbl/d; booked 4 mmbbl of proved plus probable reserves

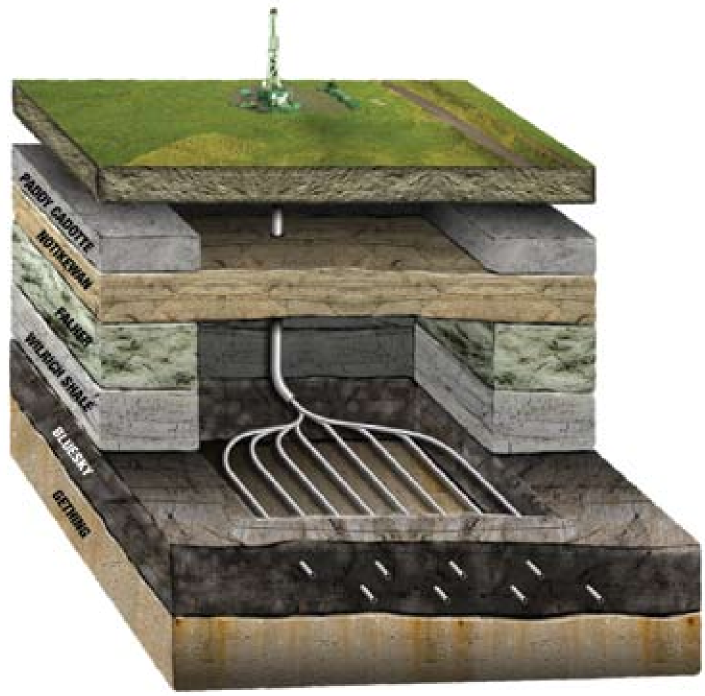
2006

- Drilled three stratigraphic test wells and two horizontal producing wells
- Initiated reservoir simulation study of enhanced oil recovery potential
- Production averaged 550 bbl/d; booked 13 mmbbl of proved plus probable reserves

Stratigraphic test wells at Seal are expendable vertical wells drilled to a depth of about 600 meters to acquire full-section cores of the Bluesky oil sand. We measure the permeability of the formation and the viscosity of the oil it contains over the cored interval. These measurements indicate whether the Bluesky oil sand is amenable to cold production, thermal production, or both methods at the stratigraphic test well location

Technology Continues to Evolve. The technology we employ at Seal continues to evolve, leading to greater production rates, increased recovery, and even stronger capital efficiencies. Our initial completion technique involved drilling mile-long single leg horizontal wells at a depth of approximately 600 metres. These wells initially produced at rates of between 150-200 bbl/d. In August 2007, we drilled our first multi-lateral well (dual-leg), and in February 2008, we drilled our first triple-lateral well. The completion technique continued to evolve throughout 2009 as we drilled one single-lateral, one dual-lateral, seven triple-lateral wells, three four-lateral wells, two six-lateral wells, and three eight-lateral wells. We are now achieving initial production rates on our eight-lateral wells in excess of 500 bbl/d. The figure opposite illustrates a typical eight-lateral well at Seal. And while it is still early in our overall Seal development, we remain excited for the long-term prospects the region offers Baytex. Importantly, our capital efficiency ratios remain strong with finding & development costs of under $5.00 per boe, and production efficiencies of under $5,000 per boe/d. In 2010, we expect to drill approximately 20 horizontal wells, largely comprised of multi-lateral wells.

EIGHT-LATERAL WELL AT SEAL



2007

- Drilled 17 new horizontal producing wells bringing the total number of producing wells to 25
- In August 2007, Baytex drilled its first multi-lateral well (dual-leg)
- Four new stratigraphic test wells drilled to identify extensions to the initial development area
- Production averaged 1,600 bbl/d; booked 28.7 mmbbl of proved plus probable reserves

2008

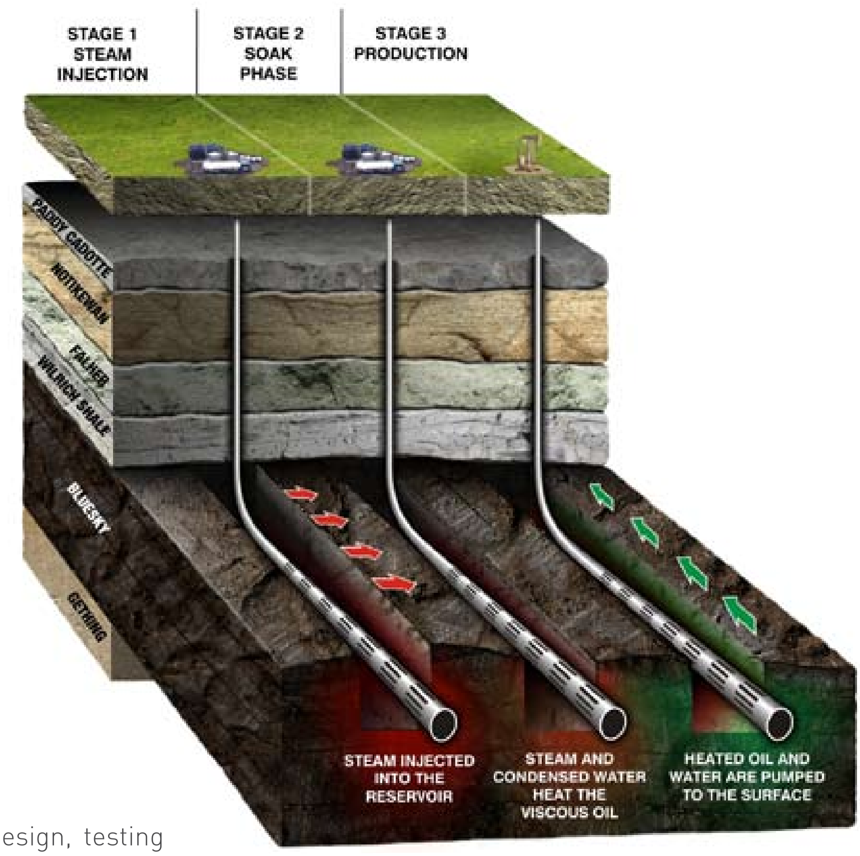
- Drilled 17 new horizontal production wells bringing the total number of producing wells to 44
- In February 2008, Baytex drilled its first triple-lateral well
- Cyclic steam pilot project carried out on an existing horizontal producer to validate the numerical reservoir simulation model
- The 2008 reserve report included the first assignment for thermal reserves at Seal
- Production averaged 3,707 bbl/d; proved plus probable reserves at Seal total 39.2 mmbbl

2009

- Drilled 17 new horizontal wells bringing the total number of wells drilled to 61, of which 59 were producing at year-end 2009
- Drilling technology continues to advance; Baytex drilled its first four-lateral, six-lateral, and eight-lateral wells
- The 2008 cyclic steam pilot project exceeds expectations; the test generated an impressive steam-oil ratio of 1.3 barrels of steam per barrel of oil
- Development plans continue for a 10-well commercial thermal project with targeted start-up of late 2011
- Production averaged 5,100 bbl/d; proved plus probable reserves at Seal total 55 mmbbl

The Next Step – Thermal Development. Under primary development, the recovery factor at Seal is estimated to be between 5% to 7% of original oil in place. Under thermal development, the recovery factor at Seal could potentially increase to 30%. In 2008, Baytex reached a significant milestone that we believe will prove important for our long-term growth. We successfully tested the application of CSS in a well that had previously been a cold producer. The results of the test significantly exceeded our expectations, with initial rates following steam injection exceeding 900 bbl/d. More importantly, the test generated an impressive incremental steam-oil ratio ("SOR") of 1.3 barrels of steam per barrel of incremental oil. This SOR is far lower than the average for projects in Western Canada, and suggests very high thermal efficiences and the potential for strong thermal operating economics. Based on our successful pilot, we are conducting the remaining design, testing and reservoir modeling activities to install a permanent steam project, with start-up targeted for late 2011. The figure above illustrates how a CSS project would work at Seal. In CSS, the same well is used for both steam injection and oil production. CSS is a lower cost form of thermally-enhanced oil recovery as compared to SAGD.

CYCLICAL STEAM STIMULATION AT SEAL



SEAL – PRIMARY DEVELOPMENT*

Cost per well (drill, complete, tie-in):	
Triple-lateral	$1.5 million
Eight-lateral	$2.0 million
Initial production rate per well:	
Triple-lateral	300 bbl/d
Eight-lateral	500+ bbl/d
EUR per well: Triple-lateral	405 mboe
Recovery factor	5% - 7% of OOIP

SEAL – THERMAL DEVELOPMENT*

Modular development – 10 wells per phase	
Phase I targeted for initial production by year-end 2011	
Capital requirement per phase	~$31 million
Anticipated production rate per phase:	
Peak year	1,700 bbl/d
Peak month	2,200 bbl/d
EUR per 10-well phase	3.8 mmbbl
Recovery factor – approximately 30% based on numerical reservoir simulation.	

*Baytex internal estimates

Emerging Light Oil Plays

More than Just Heavy Oil. Baytex has a reputation of being a heavy oil company. It is a reputation we deserve, and one of which we are quite proud. Nevertheless, we have steadily assembled an enviable suite of light oil projects – two such projects are the Bakken-Three Forks play in North Dakota and the Viking play in southwest Saskatchewan and southeast Alberta. In addition, we have a smaller presence in the Pembina Cardium trend. To develop these resource plays, we will generally utilize horizontal wells with multiple hydraulic fracture stimulations to induce light oil production from these low permeability reservoirs. The plays contain very large volumes of light oil resource in place and have the potential, over time, to generate significant increases in Baytex's light oil production and reserves.

We put these new light oil resource plays in place with three purposes in mind: value accretion to our unitholders, enhancement of our overall growth rate and maintaining diversification of our long-term product mix and project mix. The light oil resource plays will complement development of our heavy oil assets, such as our resource play at Seal.

Williston Basin – Bakken-Three Forks Project. This light oil resource play is located mainly in the Divide County of North Dakota. Baytex first acquired an interest in the play in 2008, and today has an average 38% working interest in 96,000 net acres of land, of which over 90% is undeveloped. In 2009, we drilled four gross (1.5 net) operated wells with a 100% success rate. Initial production rates from our first three operated wells averaged 300 bbl/d, exceeding our previous model for this play by about one-third. For 2010, we will see drilling activity accelerated with approximately 15-20 gross (5.6–7.5 net) wells planned. Ultimately, we believe we have the potential to develop up to 150-300 gross wells in this project.

Viking Resource Play. During 2008, we developed a new resource play in the Viking sand at Dodsland in southwest Saskatchewan and in the Bon Accord area in southeast Alberta. The Viking zone is regionally charged with light oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex has targeted the less permeable but undeveloped areas of the play. In 2008, we drilled two successful horizontal producing wells, one each in Alberta and Saskatchewan. This was followed up in 2009 with another three gross (3.0 net) successful horizontal wells in Alberta with average initial production rates for the three wells in excess of 130 bbl/d per well. Our 2009 acquisition of heavy oil producing assets in the Kerrobert area included additional highly prospective Viking light oil lands. In aggregate, Baytex has amassed over 65,000 net acres of prospective Viking lands, 95% of which are located in southwest Saskatchewan. For 2010, we expect to drill up to 10 gross (9.3 net) Viking wells, split between Alberta and Saskatchewan. Ultimately, we believe this project could yield up to 260 net drilling locations.

Baytex pump jack at Bon Accord, in Southeast Alberta

Cardium Development. Baytex's position in the emerging Cardium play is located in the Pembina trend in west central Alberta. Baytex acquired its initial position in Pembina in June 2007 through a light oil asset acquisition and further expanded its presence in the area through the acquisition of Burmis Energy in June 2008. In the Cardium we have interests in approximately 10,000 gross acres of land. In 2009, Baytex drilled two gross (2.0 net) successful Cardium horizontal wells, which were completed with multi-stage fracture stimulations. We have identified the potential to drill up to 43 gross locations which will include up to five wells for 2010.

Reserves

Since our conversion to an oil and gas royalty trust in late 2003, Baytex has continued to demonstrate superior capital and operational efficiencies as we prudently execute our strategy for long-term sustainability. Our 2009 reserve report, as prepared by our independent engineering firm, Sproule Associates Limited, continued our record of capital efficiency. Highlights from our 2009 reserve report include:

- Proved plus probable ("2P") reserves totaled 197 mmboe, an increase of 5% from 2008. Our 2P reserve breakdown is 74% heavy oil, 15% light oil and 11% natural gas. At Seal, 2P reserves increased 39% to 55 mmboe. The steady reserve growth at Seal is consistent with our long-held view that this property holds significant potential.
- Exploration and development expenditures represented 47% of funds from operations, and led to a reserve replacement ratio[1] of 113%. Finding and development costs of $9.25 per boe, excluding future development capital ("FDC"), were consistent with our three-year average of $9.67 per boe.
- Inclusive of acquisitions, we replaced 165% of 2009 production. Finding, development, and acquisition costs of $11.63 per boe, excluding FDC, were on par with our three-year average of $11.89 per boe.
- In 2009, we generated an operating netback[2] of $27.64 per boe which led to a strong recycle ratio[2] of 2.4x. Our three-year average recycle ratio[2] is 2.5x.
- Our net asset value ("NAV") (before tax) increased to $32.16 per unit, up from $31.57 per unit at 2008.

(1) Reserve replacement ratio is calculated as total reserves added in the year divided by production for the same year.

(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable excluding FDC). Operating netback is calculated as revenue less royalties, operating expenses and transportation expenses.

	Reserve Value (C$millions) Before Tax and Discounted at:		
Reserve Category	**10%**	**15%**	**20%**
Proved			
Developed Producing	1,279	1,143	1,041
Developed Non-Producing	423	342	282
Undeveloped	1,033	785	619
Total Proved	2,735	2,270	1,942
Probable	1,098	821	642
Total Proved Plus Probable	3,833	3,091	2,584

Net Asset Value (Before Tax)	**C$ Millions**
PV10 of Proved plus Probable Reserves	3,833
Undeveloped Land	221
Year-end net debt	(467)
Asset retirement obligations	(55)
	3,532
Diluted trust units (millions)	109.8
Net asset value per trust unit	$32.16

Notes: Reserve value at December 31, 2009, as evaluated by Sproule Associates Limited. Undeveloped land and asset retirement obligation evaluated by Baytex. Diluted trust units outstanding include 0.53 million trust units issuable pursuant to outstanding convertible debentures. NAV calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by Sproule. It does not take into account the possibility of Baytex being able to recognize additional reserves through future capital investment in its existing properties beyond those included in the 2009 year-end report.

	Based on Forecast Prices and Costs							
	Light Oil & NGLs		Heavy Oil		Natural Gas		Oil Equivalent	
Reserve Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mboe)	Net (mboe)
Proved								
Developed Producing	8,068	6,038	31,358	25,997	68,546	57,494	50,850	41,617
Developed Non-Producing	1,003	742	16,334	13,782	11,781	8,882	19,300	16,005
Undeveloped	8,315	6,498	49,363	41,953	9,331	7,418	59,233	49,687
Total Proved	17,386	13,278	97,055	81,732	89,658	73,794	129,383	107,309
Probable	11,733	8,930	48,542	40,960	44,089	35,015	67,624	55,726
Total Proved Plus Probable	29,119	22,208	145,597	122,692	133,747	108,809	197,007	163,035

Notes: "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others. "Net" reserves means Baytex's gross reserves less all royalties payable to others. Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Please refer to our 2009 Annual Information Form, which can be found on our website at www.baytex.ab.ca, for complete reserves disclosure.

Environment, Health & Safety

Seal development has minimal land impact

BAYTEX ENERGY TRUST'S OPERATIONS ARE DESIGNED TO PROTECT THE HEALTH AND SAFETY OF OUR EMPLOYEES, CONTRACTORS, AND THE PUBLIC AND TO AVOID AN ADVERSE IMPACT ON THE ENVIRONMENT.

Baytex Energy Trust has an Environmental, Health and Safety Policy to:

- develop and maintain health, safety and environmental management plans which include practices and procedures that comply with regulatory requirements and industry standards;
- ensure that all employees and contract personnel understand their responsibilities through education, communication and training;
- develop and maintain a contractor management program to ensure contractor and subcontractor compliance with Baytex policies;
- conduct regular reviews of the safety and environmental management system and conduct updates as required. Input from employees is encouraged and is considered when conducting reviews;
- conduct regular inspections and audits on all properties operated by Baytex; and
- develop emergency response plans and train employees to effectively respond to emergency situations.

Management is responsible for establishing health, safety and environmental policies and procedures and ensuring that all necessary resources, equipment and training are provided. In addition, corporate safety and environmental reports are presented periodically to the Board of Directors. All employees and contractors must understand and comply with all applicable policies and procedures.

In addition to the above, Baytex participates in the Canadian Association of Petroleum Producer's Environment, Health and Safety Stewardship program. This program has been developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. The program allows industry participants to measure the quality and performance of their environment, health and safety programs against other companies' programs. Baytex is proud to report that it has achieved a "Gold" ranking under this program for six years running.

Five-Year Historical Summary

Year Ended December 31,	2009	2008	2007	2006	2005
FINANCIAL (thousands of Canadian dollars, except per unit amounts)					
Petroleum and natural gas sales	**789,820**	1,159,718	745,885	556,689	546,940
Funds from operations[1]	**332,186**	433,823	286,030	274,662	227,465
Per unit - basic	**3.17**	4.73	3.57	3.77	3.38
Per unit - diluted	**3.10**	4.51	3.34	3.45	3.12
Cash distributions declared	**137,601**	197,026	145,927	143,072	114,221
Per unit	**1.56**	2.64	2.16	2.16	1.80
Net income	**87,574**	259,894	132,860	147,069	79,876
Per unit - basic	**0.83**	2.83	1.66	2.02	1.19
Per unit - diluted	**0.82**	2.74	1.60	1.91	1.15
Total monetary debt[1]	**474,276**	533,092	444,065	366,810	418,476
Operating netback (C$/boe)					
Sales price	**45.00**	65.66	46.53	44.48	42.60
Financial instruments gain (loss)	**5.36**	(4.05)	(0.24)	0.20	(3.77)
Royalties	**(8.67)**	(13.99)	(7.70)	(6.80)	(6.38)
Operating expenses	**(10.83)**	(11.62)	(10.09)	(8.98)	(8.62)
Transportation expenses	**(3.22)**	(2.83)	(2.31)	(1.95)	(1.74)
Operating netback	**27.64**	33.17	26.19	26.95	22.09
Capital expenditures					
Exploration and development	**157,044**	184,678	148,719	132,381	130,492
Acquisitions, net of dispositions	**133,077**	265,099	245,427	702	21,957
Total capital expenditures	**290,121**	449,777	394,146	133,083	152,449
OPERATING					
Daily production					
Light oil & NGL (bbl/d)	**6,937**	7,575	5,483	3,735	3,842
Heavy oil (bbl/d)	**24,678**	23,530	22,092	21,325	21,265
Total oil (bbl/d)	**31,615**	31,105	27,575	25,060	25,107
Natural gas (mmcf/d)	**58.6**	54.8	51.9	55.4	60.4
Oil equivalent (boe/d @ 6:1)[2]	**41,382**	40,239	36,222	34,292	35,177
Percent oil	**76%**	77%	76%	73%	71%
Proved plus probable reserves					
Light oil & NGL (mmbbl)	**29.1**	31.4	20.8	11.7	12.7
Heavy oil (mmbbl)	**145.6**	126.1	122.5	108.7	97.6
Total oil (mmbbl)	**174.7**	157.5	143.3	120.4	110.3
Natural gas (bcf)	**133.7**	178.2	148.9	148.1	176.4
Oil equivalent (mmboe)[2]	**197.0**	187.1	168.1	145.1	139.7
Net asset value @ 10% pre-tax (C$/unit)	**32.16**	31.57	24.23	17.55	19.96
FD&A costs (proved plus probable, excluding FDC) (C$/boe)	**11.63**	13.11	10.90	7.31	4.70
Recycle ratio	**2.4**	2.5	2.4	3.7	4.7
TRUST UNIT INFORMATION					
TSX					
Unit price (C$)					
High	**30.50**	35.37	22.92	28.66	18.78
Low	**9.77**	12.81	16.68	16.81	12.42
Close	**29.70**	14.65	19.00	22.28	17.70
Average daily volume traded	**446,799**	489,752	342,004	408,973	348,531
NYSE [3]					
Unit price (US$)					
High	**29.32**	35.20	21.74	25.87	-
Low	**7.84**	10.16	15.51	16.63	-
Close	**28.30**	11.95	19.11	18.96	-
Average daily volume traded	**131,908**	136,418	71,962	110,805	-
Units outstanding at December 31 (thousands)	**109,299**	97,685	87,169	77,498	71,475

1) Funds from operations and total monetary debt are non-GAAP terms. For further explanation refer to the Management's Discussion and Analysis for the year ended December 31, 2009.

2) 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.

3) Data reflects the periods since commencement of trading on March 27, 2006 on the NYSE.

Corporate Information

DIRECTORS

Raymond T. Chan
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Partner
Burnet, Duckworth & Palmer LLP

Edward Chwyl
Lead Independent Director
Independent Businessman

Naveen Dargan
Independent Businessman

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

Anthony W. Marino
President & Chief Executive Officer
Baytex Energy Ltd.

Gregory K. Melchin
Independent Businessman

Dale O. Shwed
President & Chief Executive Officer
Crew Energy Inc.

OFFICERS

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Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
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Stephen Brownridge
Vice President, Exploration

Murray J. Desrosiers
Vice President,
General Counsel
and Corporate Secretary

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, U.S. Business
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EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
°API	American Petroleum Institute gravity
bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
EUR	estimated ultimate recovery
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
mmboe	million barrels of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids

BAYTEX

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