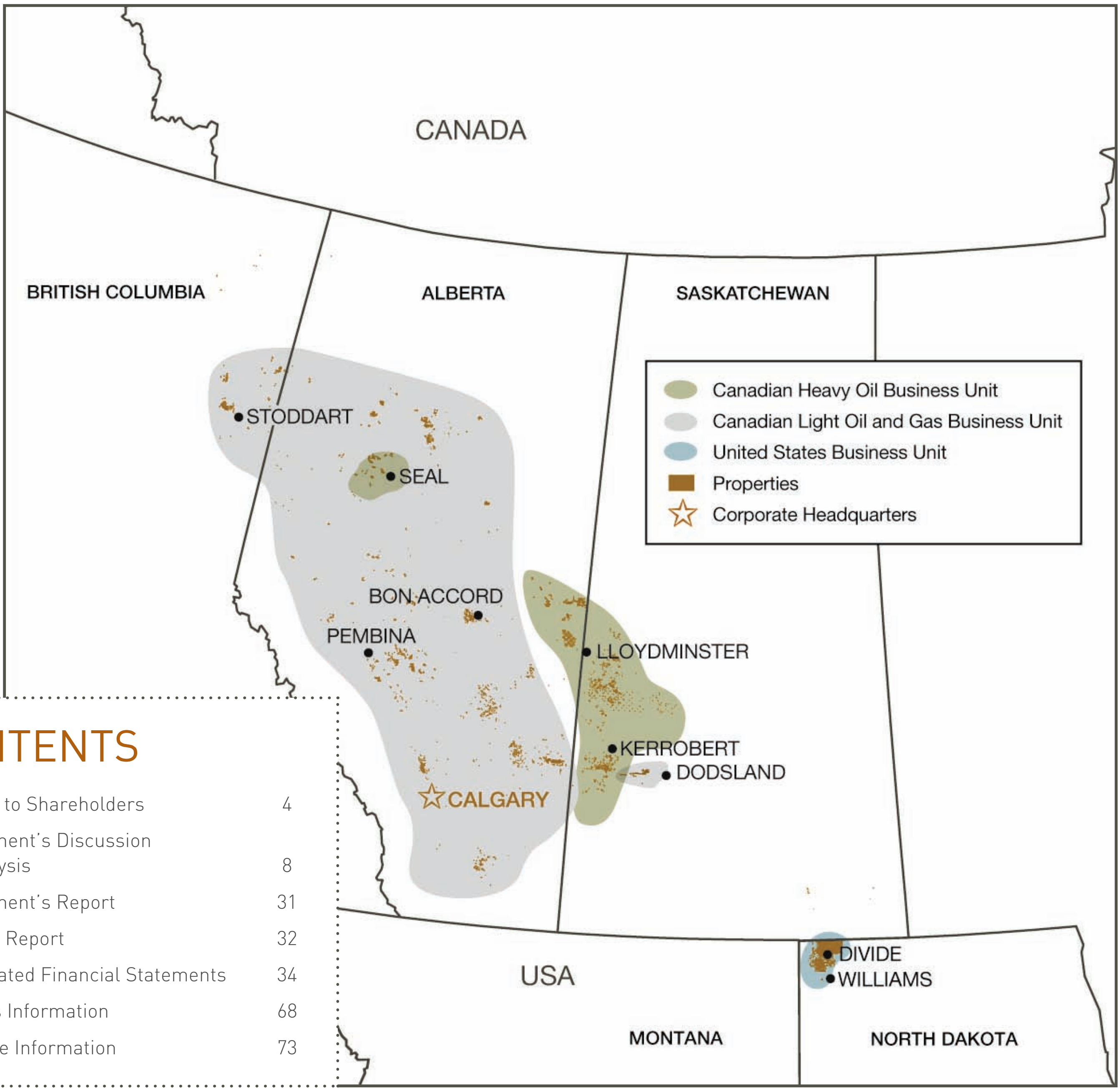
2010 ANNUAL REPORT

BAYTEX ENERGY CORP.

Operating Areas



CONTENTS

HIGHLIGHTS

	Three Months Ended			Years Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
FINANCIAL *(thousands of Canadian dollars, except per common share or unit amounts)*					
Petroleum and natural gas sales	**263,497**	238,293	237,962	**1,005,136**	789,743
Funds from operations(1)	**124,776**	112,786	97,344	**454,183**	332,186
Per share or unit – basic	**1.10**	1.01	0.90	**4.08**	3.17
Per share or unit – diluted	**1.07**	0.97	0.87	**3.93**	3.10
Cash distributions declared(2)	**48,126**	45,795	37,286	**189,824**	137,601
Per unit	**0.56**	0.54	0.42	**2.18**	1.56
Net income	**57,589**	35,061	27,956	**177,631**	87,574
Per share or unit – basic	**0.51**	0.31	0.26	**1.59**	0.83
Per share or unit – diluted	**0.49**	0.30	0.25	**1.54**	0.82
Exploration and development	**55,175**	62,245	45,471	**236,979**	157,044
Acquisitions	**4,846**	12,875	37,143	**24,763**	133,155
Dispositions	**(896)**	(18,087)	(60)	**(19,033)**	(78)
Corporate acquisition	**–**	–	–	**40,914**	–
Total oil and gas expenditures	**59,125**	57,033	82,554	**283,623**	290,121
Bank loan	**303,773**	314,567	265,088	**303,773**	265,088
Convertible debentures	**–**	5,057	7,736	**–**	7,736
Long-term notes	**150,000**	150,000	150,000	**150,000**	150,000
Working capital deficiency	**48,417**	66,596	51,452	**48,417**	51,452
Total monetary debt(3)	**502,190**	536,220	474,276	**502,190**	474,276

(1) Funds from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months and year ended December 31, 2010.

(2) Cash distributions declared are net of DRIP.

(3) Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative contracts gains or losses)), the balance sheet value of the convertible debentures, long-term bank loan and the principal amount of long-term debt.

	Three Months Ended			Years Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**6,457**	6,600	6,541	**6,539**	6,937
Heavy oil (bbl/d)	**29,808**	28,959	26,423	**28,585**	24,678
Total oil (bbl/d)	**36,265**	35,559	32,964	**35,124**	31,615
Natural gas (mmcf/d)	**52.5**	55.4	58.5	**55.3**	58.6
Oil equivalent (boe/d @ 6:1)(1)	**45,015**	44,799	42,713	**44,341**	41,382
Average prices (before hedging)					
WTI oil (US$/bbl)	**85.17**	76.20	76.19	**79.53**	61.80
Edmonton par oil ($/bbl)	**80.73**	74.43	76.73	**77.81**	66.20
BTE light oil and NGL ($/bbl)	**68.07**	63.13	62.68	**65.90**	54.25
BTE heavy oil ($/bbl)(2)	**60.10**	57.97	57.24	**59.40**	49.88
BTE total oil ($/bbl)	**61.53**	58.93	58.31	**60.61**	50.85
BTE natural gas ($/mcf)	**3.84**	3.89	4.87	**4.32**	4.35
BTE oil equivalent ($/boe)	**53.99**	51.59	51.71	**53.39**	45.00
USD/CAD noon rate at period end	**1.0054**	0.9711	0.9555	**1.0054**	0.9555
USD/CAD average rate for period	**0.9873**	0.9624	0.9467	**0.9708**	0.8760
COMMON SHARE OR TRUST UNIT INFORMATION					
TSX					
Unit price (Cdn$)					
High	**$ 48.15**	$ 37.86	$ 30.50	**$ 48.15**	$ 30.50
Low	**$ 37.12**	$ 31.27	$ 21.57	**$ 27.72**	$ 9.77
Close	**$ 46.61**	$ 37.27	$ 29.70	**$ 46.61**	$ 29.70
Volume traded (thousands)	**32,579**	21,917	22,820	**105,385**	112,146
NYSE					
Unit price (US$)					
High	**$ 47.82**	$ 36.90	$ 29.32	**$ 47.82**	$ 29.32
Low	**$ 35.96**	$ 25.64	$ 19.83	**$ 25.64**	$ 7.84
Close	**$ 46.82**	$ 36.33	$ 28.30	**$ 46.82**	$ 28.30
Volume traded (thousands)	**5,231**	4,514	5,492	**21,489**	33,241
Common shares or trust units outstanding (thousands)	**113,712**	112,333	109,299	**113,712**	109,299

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Heavy oil wellhead prices are net of blending costs.

Forward-Looking Statements

This report contains forward-looking statements relating to: our business strategies, plans and objectives; our ability to grow our reserve base and add to production levels through exploration and development activities complemented by strategic acquisitions; contingent resource estimates and the assumptions relating thereto; our heavy oil resource play at Seal, including our ability to improve production rates, recoveries and capital efficiencies through enhanced development techniques and the timing of completing a thermally-enhanced oil recovery project; our Bakken/Three Forks and Viking light oil resource plays, including their resource potential and their potential to grow our light oil production and reserves; initial production rates from new wells; the pricing differential between Western Canadian Select and West Texas Intermediate crude oils; our dividend policy and level; our payout ratio for 2011; our debt-to-funds from operations ratio; our liquidity and financial capacity; our exploration and development capital expenditures for 2011; our average production rate for 2011; and our ability to fund our capital expenditures and dividends from funds from operations in 2011. 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. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. The level of future cash dividends will depend on the amount of funds from operations generated by our operations and our prevailing financial circumstances at the time. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Contingent Resources

This report contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Baytex will produce any portion of the volumes currently classified as contingent resources. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

Non-GAAP Financial Measures

In this report we refer to certain measures that are commonly used in the oil and gas industry but are not based on generally accepted accounting principles in Canada, such as funds from operations and total monetary debt. For a description of these measures, we refer you to "Non-GAAP Financial Measures" in the Management's Discussion and Analysis section of this report.

MESSAGE TO SHAREHOLDERS

We are pleased to report our 2010 results to our shareholders. In 2010, we achieved record levels of production, reserves and 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 fortunate to deliver, for the second consecutive year, the strongest total market return performance among our peer group. This market recognition again leaves us honoured, and also determined to continue to focus on delivering sustainable income and growth to our shareholders.

We crossed an important milestone at the end of 2010. Effective December 31, we converted our legal structure from an income trust to a corporation, returning to the legal form that Baytex used in its original incarnation from 1993 to 2003. We pledge to our shareholders that we will remember the lessons of capital efficiency we learned in our seven years as an income trust. We will do our best to even more effectively execute our growth and income model as Baytex Energy Corp.

Operations Review

Production averaged 45,015 boe/d in the fourth quarter of 2010, and 44,341 boe/d for the full year, a 7% increase over 2009. Production increased each quarter during 2010, with the fourth quarter marking our eighth consecutive quarter of production growth. With respect to product mix, Baytex is one of the most oil-weighted entities in the North American energy industry, with 83% of our production and 91% of our reserves represented by heavy oil, light oil and natural gas liquids.

Our 2010 capital expenditures ("CAPEX") for E&D activities increased 51% from 2009 levels, reflective of both the end of the economic recession and higher growth rates for Baytex. Spending for E&D totaled $237 million, with the majority directed toward heavy oil projects. During the year, Baytex participated in the drilling of 155 gross (118.2 net) wells on our heavy oil, light oil and natural gas properties, generating a 97% success rate.

Our total capital program for 2010, including acquisitions net of dispositions, amounted to $284 million, about 2% less than in 2009. We only pursue acquisitions that meet three criteria: value accretion for our existing shareholders, growth potential for the acquired assets, and operating control and capability by Baytex. As a result of these restrictive criteria, we are not a frequent acquirer, and 2010 was a year of lower acquisition activity. Subsequent to year-end 2010, we did, however, close an accretive acquisition of heavy oil assets in the Seal and Lloydminster areas in February 2011 (the "2011 Heavy Oil Acquisition").

This CAPEX program allowed Baytex to increase its reserve base in both proved and probable reserve categories for the seventh consecutive year. At year-end 2010, our proved plus probable reserves, as evaluated by Sproule Associates Limited, reached 229 million boe. This reserve total represents a 13.2 year reserve life index based on our expected production rates for 2011. Neither these reserve levels nor reserve life index take into account the 2011 Heavy Oil Acquisition.

We released a contingent resource assessment prepared by Sproule Associates Limited for three of our resource plays (Seal, Bakken/Three Forks and Viking). At year-end 2010, the estimate of contingent resource ranged from 528 million barrels of oil and bitumen in the "Low Estimate" to 1.02 billion barrels of oil and bitumen in the "High Estimate", with a "Best Estimate" of 668 million barrels of oil and bitumen. During 2010, our E&D activities converted 17 million barrels of contingent resource into proved reserves and 42 million barrels of contingent resource into proved plus probable reserves.

Baytex continued to record strong CAPEX efficiencies in 2010. Finding, development and acquisition costs were $5.90/boe on a proved plus probable basis (excluding changes in future development costs), resulting in a recycle ratio of 5.6 times. Our strong capital efficiency is further demonstrated by replacement of 271% of the year's production through E&D, while reinvesting only 52% of funds from operations ("FFO") into E&D activities. Including acquisitions, we replaced 297% of our 2010 production while investing 62% of FFO. These results are consistent with our long-term performance in capital efficiency. Our five-year average finding, development and acquisition cost of $9.59/boe (excluding changes in future development costs), recycle ratio of 3.1 times and reserve replacement ratio of 225% all rank among the best in our industry.

At Seal in the Peace River oil sands region, we drilled 15 new cold horizontal producers, continuing our record of 100% drilling success and increasing production from this important growth property to more than 10,000 bbl/d by the end of 2010. We advanced our use of multi-lateral horizontal wells at Seal to increase cold production rates and recoveries, and to further improve our capital efficiencies. During 2010, we conducted a second cyclic steam stimulation ("CSS") pilot, which we believe noteworthy because it was a multi-cycle test and was implemented in a part of Seal where there was no prior cold development. We plan to install our first commercial thermally-enhanced oil recovery project at Seal in 2011. We also drilled seven stratigraphic test wells to further delineate our land base for both cold and thermal development in the years ahead.

Production from our Lloydminster core heavy oil area was basically unchanged from 2009 levels as drilling, recompletion of existing wells and a small corporate acquisition in the second quarter of 2010 offset natural production declines. Our thermal operations continue to expand in the Lloydminster area, including the drilling and completion of a new steam-assisted gravity drainage well pair in late 2010 which was producing over 1,000 bbl/d in early March 2011.

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 shareholders, enhancement of our overall growth rate and diversification of our long-term product and project mix. These light oil resource plays complement the growth of our heavy oil projects at Seal and Lloydminster.

In the Bakken-Three Forks in Divide and Williams Counties, North Dakota, we expanded our land base to approximately 125,000 net acres during 2010. Drilling activity will continue to increase in 2011, as we drill a mix of well lengths that is increasingly oriented to two-mile long horizontal wells, which have exhibited initial production rates of approximately 400 bbl/d per well.

In our Viking play in Alberta, we drilled seven successful multi-lateral horizontal wells (without hydraulic fracturing) with an average initial production rate of approximately 100 bbl/d per well. During 2011, 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 has allowed us to successfully execute our growth and income model in a variety of commodity price environments.

West Texas Intermediate ("WTI") oil price for 2010 averaged US$79.53/bbl, an increase of 29% from the average for 2009. Because WTI prices are denominated in US dollars, a strengthening Canadian currency partially reduced the positive impact of the oil price recovery for Canadian producers. The Canadian dollar rose to an average of US$0.97 during 2010, an increase of 11% over 2009. For some time, we have been of the view that the Canadian currency was likely to strengthen versus the US dollar, and put in place currency hedges to protect about 39% of our foreign exchange exposure for 2010, thereby reducing the impact of the stronger Canadian dollar on our 2010 FFO. As we will discuss later, we have also arranged our debt structure to mitigate our exposure to a weaker US dollar.

We are fortunate to be particularly weighted to heavy oil, which has benefitted for the past few years from a narrowing of differentials and reduced volatility as compared to WTI. This long-term improvement in heavy oil differentials is the result of a number of North American and global supply/demand factors, including 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 US markets.

The heavy blend benchmark, Western Canadian Select ("WCS"), sold at an 18% discount to WTI during 2010, as compared to a 16% discount during 2009. This modestly-higher WCS discount was primarily due to transportation constraints resulting from service disruptions on two oil export pipelines, which temporarily curtailed oil shipments to US refineries and resulted in wider price differentials for all Canadian crude oil grades during the second half of

2010. During the fourth quarter of 2010, these pipelines were repaired and deliveries resumed. As of this writing, the forward strip suggests a WCS differential of approximately 20% for the April to December 2011 period, resulting in wellhead prices for heavy oil that are yielding very high rates of return on our investment program.

Natural gas prices remained depressed during 2010. The average price for natural gas at the AECO hub was $4.13 per mmBtu, essentially unchanged from 2009. With only 10% of our revenue coming from natural gas in 2010, fluctuations in natural gas prices had a minor impact on our FFO.

Operating expenses decreased for the second consecutive year despite increases in costs for fuel and oilfield services. For 2010, our operating expense averaged $10.62/boe, a 2% decrease from 2009. Transportation expense decreased by 9% to $2.92/boe as a result of optimization of delivery points for our production from Seal. General and administrative expense ("G&A") expenses increased 6% to $2.46/boe. We do not capitalize any G&A costs, and our G&A expense has consistently been at or below the average for our peer group.

FFO for 2010 was our highest ever at $454 million, an increase of 37% from 2009. Despite fluctuations in commodity prices during the year, FFO increased each quarter during 2010, from a low of $107 million in the first quarter to a high of $125 million in the fourth quarter. As is the case with production, FFO has grown for eight consecutive quarters.

As a result of the improvement in commodity prices and our strong operating results, we increased our monthly distribution from $0.18 to $0.20 per unit in December 2010. As a corporation, we will continue to pay monthly dividends, with our initial dividend level set at $0.20 per share. Cash distributions for 2010 were $190 million, bringing our cumulative cash distributions to $1.1 billion since trust inception in 2003.

Our payout ratio for 2010 averaged 42%, net of participation in our distribution reinvestment plan. Importantly, we were able to fully fund 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 dividend of $0.20 per share, our payout ratio (net of participation in our dividend reinvestment plan) is forecast to be approximately 36% for 2011, based on the commodity price strip from early March 2011.

Total monetary debt at year-end 2010 was $502 million, which represented a debt-to-FFO ratio of 1.1 times based on 2010 FFO. Pro forma the 2011 Heavy Oil Acquisition, our debt-to-FFO ratio is 1.1 times based on projected 2011 FFO (using the commodity price strip from early March 2011).

The majority of our debt is represented by drawings on our reserve-based revolving credit facilities, which are provided by a syndicate of nine banks from Canada, the US and Europe. We are also pleased to note that our banking syndicate increased our credit facilities to $550 million in June 2010, to $625 million in January 2011, and to $650 million in February 2011 (following the closing of the 2011 Heavy Oil Acquisition).

In February 2011, our financial strength was further enhanced when we issued US$150 million of 6.75% ten-year senior unsecured debentures in the Canadian non-investment grade bond market. Our issue was the first US dollar denominated issue of its type in this developing debt market. We used the proceeds from the sale of the debentures to reduce Canadian dollar borrowings on our revolving credit facilities. The US dollar debt issue provides a partial hedge against further weakness in the US dollar relative to the Canadian dollar. Pro forma the debenture issue and the reduction in bank debt, our undrawn credit facilities are approximately $335 million, representing greater than 50% of the total credit facilities. Our new US dollar denominated Canadian debt issue and our history as an issuer in the Canadian and US bond markets illustrate our capability to access the debt markets should we have a need for external financing.

Outlook

My main message to you is that we intend to follow the same strategy as Baytex Energy Corp. that we have for the past few years as Baytex Energy Trust. Internally within Baytex, we intend to keep our organization as technically-focused and as non-bureaucratic as possible. In terms of external communication, we pledge to continue to communicate with our shareholders in a complete and forthright manner. As in the past, we will emphasize organic growth, occasionally augmented by accretive acquisitions that bring their own enhancements to our future organic growth profile.

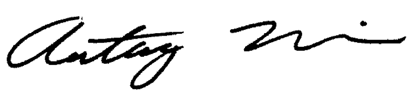
We remain committed to providing a combination of growth and income to the owners of our company. We are sometimes asked why a company with so many high-return projects chooses to pay a dividend. It is our view that the income component of our total return has several advantages for our shareholders. We believe that a dividend-paying stock reduces investment risk by stabilizing a portion of total return. Our market assessment is that dividends meet the income needs of many investors and are, as a result, desired by a large segment of the equity market. We believe that a combination of income and growth will offer the most reliable path to long-term total return. Finally, as we learned in the trust era, returning a portion of our cash flow stream to investors helps keep companies disciplined in capital investment decisions – a critical element of success in a capital-intensive business like oil and gas.

The market rewarded our disciplined approach with an energy trust sector-leading total market return of 67% during 2010, including both appreciation of our unit price and reinvestment of distributions. This was the second consecutive year we led the energy trust sector in total return. Our total return over our seven-year tenure as a trust was 876%, the highest in the sector, and significantly higher than the 206% return of the S&P/TSX Capped Energy Trust Index and the 230% return of the corporate S&P/TSX Oil & Gas E&P Index over the same period.

In our first year as a corporation, our capital budget of $325 million for E&D is designed to generate average production of 49,000 to 50,000 boe/d (including the pro-rated impact of the 2011 Heavy Oil Acquisition), an increase of approximately 10% over 2010. Based on the current commodity price strip, we expect to generate sufficient FFO in 2011 to fully fund our E&D CAPEX and our dividends.

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 shareholders in our new corporate era. 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, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the year ended December 31, 2010. This information is provided as of March 15, 2011. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Company's audited consolidated comparative financial statements for the years ended December 31, 2010 and 2009, together with accompanying notes, and the Annual Information Form for the year ended December 31, 2010. The Company's Annual Information Form for the year ended December 31, 2010, will be filed in late March 2011. These documents and additional information about Baytex are available on SEDAR at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentage and per common share or per trust unit amounts or as otherwise noted.

In this MD&A, 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 equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

CORPORATE CONVERSION

At year-end 2010, Baytex Energy Trust (the "Trust") completed a plan of arrangement under the Business Corporations Act (Alberta) pursuant to which it converted its legal structure from an income trust to a corporation (the "Corporate Conversion"). Pursuant to the Corporate Conversion: (i) on December 31, 2010, holders of trust units of the Trust exchanged their trust units for our common shares on a one-for-one basis; and (ii) on January 1, 2011, the Trust was dissolved and terminated, with the result that we became the successor to the Trust. The reorganization into a corporation has been accounted for on a continuity of interest basis and accordingly, the consolidated financial statements reflect the financial position, results of operations, and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

Despite the change in legal structure from a trust to a dividend paying corporation, the Company's business objectives and strategies remain unchanged and all officers and directors remain the same. Baytex's business objectives are directed towards growing its production and asset base through internal property development and acquisitions with the objectives of providing monthly income to its Shareholders and creating long-term value for its Shareholders. This will be maintained by investing capital to enhance the value of Baytex's assets, operating Baytex's producing oil and gas properties in a low cost manner to maximize the recovery of reserves, and paying monthly dividends to Shareholders.

Baytex will continue to direct its efforts to increase the value of its assets through development drilling and associated development activities and enhanced oil recovery activities as well as by the periodic acquisition of undeveloped and producing oil and gas properties. Baytex will also seek to acquire oil and natural gas producing properties and primarily participate in development activities that are generally considered to be of a low risk nature in the oil and gas industry. Also, a minor percentage of each year's capital budget will be devoted to moderate risk development and lower risk exploration opportunities on its properties.

The Common Shares of Baytex trade on the Toronto Stock Exchange (the "TSX") and the New York Stock Exchange (the "NYSE") under the trading symbol BTE. Beginning with the January 31, 2011 record date, shareholders of Baytex will receive payments in the form of dividends. Prior to the Corporate Conversion on December 31, 2010, distributions were paid to unitholders.

NON-GAAP FINANCIAL MEASURES

Baytex evaluates performance based on net income and funds from operations. Funds from operations is not a measurement based on Generally Accepted Accounting Principles in Canada (“Canadian GAAP”), but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Company’s determination of funds from operations may not be comparable with the calculation of similar measures for other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. The most directly comparable measures calculated in accordance with Canadian GAAP are cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see “Funds from Operations, Payout Ratio and Distributions or Dividends”.

Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized gains or losses on financial derivative contracts)), the principal amount of long-term debt and the balance sheet amount of the convertible debentures and long-term bank loan.

Operating netback is a non-GAAP measure commonly used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product. There is no standardized measure of operating netback and therefore operating netback as presented may not be comparable to similar measures presented by other issuers. Operating netback is equal to product revenue less royalties, operating expenses and transportation expenses divided by barrels of oil equivalent.

OUTLOOK – ECONOMIC ENVIRONMENT

In 2010, the energy and commodity markets continued to improve. The spot price for West Texas Intermediate (“WTI”) at December 31, 2010 was US$91.38/bbl, up from US$79.36/bbl at December 31, 2009 showing continued strength in crude oil prices in the commodity marketplace. Going forward, Baytex continues to be focused on the following objectives: preserving balance sheet strength and liquidity, maintaining and, where possible, profitably expanding its productive capacity and delivering a sustainable dividend to its shareholders.

2010 OVERVIEW

Baytex is a Calgary, Alberta based conventional oil and gas corporation engaged in the acquisition, development and production of petroleum and natural gas in the Western Canadian Sedimentary Basin and the United States.

Our business has been to increase production levels through investing approximately half of our internally generated funds from operations in Exploration and Development ("E&D") activities while distributing most of the balance of our funds from operations to holders of our trust units. Over our life as a trust, we have grown our reserve base and added to production levels through E&D activities complimented by strategic acquisitions.

During 2010, Baytex executed a successful capital program, resulting in the replacement of 274% of production (on a proved plus probable basis) by reinvesting 52% of our internally generated funds from operations into E&D activities. When acquisitions are included, Baytex replaced 297% of production.

As at December 31, 2010, we had a reserve base of 229 million boe on a proved plus probable basis. During the year ended December 31, 2010, our production averaged 44,341 boe/d, primarily from Canada.

On May 26, 2010, we closed the acquisition of a private entity with heavy oil assets in the Lloydminster area of Saskatchewan for total net consideration of $40.9 million, adding approximately 900 bbl/d of oil production at accretive metrics.

In the second quarter of 2010, Baytex expanded our Bakken/Three Forks position in the United States to approximately 124,000 net acres, including the addition of high working interest lands in Williams County, North Dakota.

In 2010, we conducted a number of successful thermal development projects employing technology to create greater production rates, increased recovery and stronger capital efficiencies.

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2010	2009	*Change*
Daily Production			
Light oil and NGL (bbl/d)	6,539	6,937	*(6%)*
Heavy oil (bbl/d)[1]	28,585	24,678	*16%*
Natural gas (mmcf/d)	55.3	58.6	*(6%)*
Total production (boe/d)	44,341	41,382	*7%*
Production Mix			
Light oil and NGL	15%	17%	
Heavy oil	64%	60%	
Natural gas	21%	23%	

(1) Heavy oil sales volumes may differ from reported production volumes due to changes to the Company's heavy oil inventory. For the year ended December 31, 2010, heavy oil sales volumes were 36 bbl/d lower than production volumes (year ended December 31, 2009 – 91 bbl/d lower).

Production for the year ended December 31, 2010 totaled 44,341 boe/d, as compared to 41,382 boe/d for the same period in 2009. Light oil and natural gas liquids ("NGL") production for the year ended December 31, 2010 decreased by 6% to 6,539 bbl/d from 6,937 bbl/d in the same period last year due to production declines in conventional fields in Alberta and British Columbia, partially offset by increasing production from light oil resource plays. Heavy oil production for the year ended December 31, 2010 increased by 16% to 28,585 bbl/d from 24,678 bbl/d in the same period last year primarily due to increased production from development programs and, to a lesser extent, the acquisition of producing assets. Natural gas production decreased by 6% to 55.3 mmcf/d for the year ended December 31, 2010, as compared to 58.6 mmcf/d for the same period last year primarily due to natural declines as we focused our drilling effort on our oil portfolio.

Commodity Prices

Crude Oil

For the year ended December 31, 2010, the price of WTI fluctuated between a low of US$68.01/bbl and a high of US$92.19/bbl, as global markets showed sustained signs of recovery from the largest economic downturn since the Great Depression of the 1930s. As concerns over a "double-dip" United States recession began to fade, aided by the United States Federal Reserve's announced second round of quantitative easing in November 2010, and the European Central Bank intervention in the emerging fiscal crises of some smaller members, markets refocused on the global recovery and renewed growth potential. Oil prices were buoyed by this improving economic climate and evidence of significant third and fourth quarter petroleum demand growth from China and other emerging economies. As a result, the average prompt WTI price in the year ended December 31, 2010 increased 29% to US$79.53/bbl, from US$61.80/bbl in year ended December 31, 2009.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 18% in the year ended December 31, 2010, compared to 16% in year ended December 31, 2009. This increased WCS discount was due, in large part, to transportation constraints resulting from service disruptions on key oil export pipelines, which temporarily curtailed oil shipments to United States mid-continent refineries and resulted in wider price differentials for all Canadian crude oil grades for September and October 2010 production. During the fourth quarter, these pipelines were repaired and deliveries resumed.

Natural Gas

For the year ended December 31, 2010, AECO natural gas prices averaged $4.13/mcf, which was essentially unchanged from 2009 ($4.14/mcf). This was due to continued United States natural gas production increases and high natural gas storage levels. Canadian natural gas prices were further hindered by the increasing value of the Canadian dollar in 2010 versus the U.S. dollar during the year.

	Years Ended December 31		
	2010	2009	*Change*
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 79.53	$ 61.80	*29%*
WCS heavy oil (US$/bbl)[2]	$ 65.30	$ 52.14	*25%*
Heavy oil differential[3]	(18%)	(16%)	
USD/CAD average exchange rate	0.9708	0.8760	*11%*
Edmonton par oil ($/bbl)	$ 77.81	$ 66.20	*18%*
AECO natural gas price ($/mcf)[4]	$ 4.13	$ 4.14	*–%*
Baytex Average Sales Prices[6]			
Light oil and NGL ($/bbl)	$ 65.90	$ 54.25	*21%*
Heavy oil ($/bbl)[5]	$ 60.08	$ 55.01	*9%*
Physical forward sales contracts loss ($/bbl)	(0.68)	(5.13)	
Heavy oil, net ($/bbl)	$ 59.40	$ 49.88	*19%*
Total oil and NGL, net ($/bbl)	$ 60.61	$ 50.85	*19%*
Natural gas ($/mcf)[6]	$ 4.22	$ 4.09	*3%*
Physical forward sales contracts gain ($/mcf)	0.10	0.26	
Natural gas, net ($/mcf)	$ 4.32	$ 4.35	*(1%)*
Summary			
Weighted average ($/boe)[6]	$ 53.75	$ 48.23	*11%*
Physical forward sales contracts loss ($/boe)	(0.36)	(3.23)	
Weighted average, net ($/boe)	$ 53.39	$ 45.00	*19%*

(1) WTI refers to the calendar monthly average based on NYMEX prompt month WTI.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) Heavy oil differential refers to the WCS discount to WTI.
(4) AECO refers to the AECO monthly index price published by the Canadian Gas Price Reporter.
(5) Baytex's realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(6) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivative contracts.

For the year ended December 31, 2010, Baytex's average sales price for light oil and NGL was $65.90/bbl, up 21% from $54.25/bbl in the year ended December 31, 2009. Baytex's realized heavy oil price during the year of 2010, prior to physical forward sales contracts, was $60.08/bbl, or 89% of WCS. This compares to a realized heavy oil price in year ended December 31, 2009, prior to physical forward sales contracts, of $55.01/bbl, or 92% of WCS. The differential to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the year ended December 31, 2010, was $59.40/bbl, up 19% from $49.88/bbl in the year ended December 31, 2009. Baytex's realized natural gas price for the year ended December 31, 2010 was $4.22/mcf, prior to physical forward sales contracts, and $4.32/mcf inclusive of physical forward sales contracts (year ended December 31, 2009 – $4.09/mcf prior to, and $4.35/mcf inclusive of, physical forward sales contracts).

Revenue

($ thousands except for %)	Years Ended December 31 2010	2009	Change
Oil revenue			
Light oil and NGL	$ 157,603	$ 137,379	*15%*
Heavy oil	618,969	447,674	*38%*
Total oil revenue	776,572	585,053	*33%*
Natural gas revenue	87,116	93,918	*(7%)*
Total oil and gas revenue	863,688	678,971	*27%*
Sales of heavy oil blending diluent	141,448	110,772	*28%*
Total petroleum and natural gas sales	$ 1,005,136	$ 789,743	*27%*

For the year ended December 31, 2010, petroleum and natural gas sales increased 27% to $1,005.1 million from $789.7 million for the same period in 2009. During this period, the change was driven by a 38% increase in heavy oil revenues, which was comprised of a 19% increase in realized price and a 16% increase in sales volume compared to the year ended December 31, 2009.

Royalties

($ thousands except for % and per boe)	Years Ended December 31 2010	2009	Change
Royalties	$ 162,332	$ 130,705	*24%*
Royalty rates:			
Light oil, NGL and natural gas	20.5%	20.5%	
Heavy oil	18.2%	18.7%	
Average royalty rates[1]	18.8%	19.3%	
Royalty expenses per boe	$ 10.04	$ 8.67	*16%*

(1) Average royalty rate excludes sales of heavy oil blending diluents and the effects of financial derivative contracts.

Total royalties for the year ended December 31, 2010 increased 24% to $162.3 million from $130.7 million in the year ended December 31, 2009 as petroleum and natural gas sales increased 27%. Total royalties for the year ended December 31, 2010 averaged 18.8% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 19.3% for the same period in 2009.

Certain additional credits earned under the Alberta Royalty Drilling Credit program, which are based on drilling activity and drilling depths, are recorded as a reduction to capital expenditures, rather than as a reduction in royalties.

Financial Derivative Contracts

($ thousands)	Years Ended December 31 2010	2009	Change
Realized gain on financial derivative contracts[1]			
Crude oil	$ 7,609	$ 62,076	$ (54,467)
Natural gas	11,322	3,565	7,757
Foreign currency	28,119	15,177	12,942
Interest rate	1,079	–	1,079
Total	$ 48,129	$ 80,818	$ (32,689)
Unrealized gain (loss) on financial derivative contracts[2]			
Crude oil	$ (17,546)	$ (77,093)	$ 59,547
Natural gas	(641)	(1,142)	501
Foreign currency	(9,261)	23,804	(33,065)
Interest rate	(10,746)	(379)	(10,367)
Total	$ (38,194)	$ (54,810)	$ 16,616
Total gain (loss) on financial derivative contracts			
Crude oil	$ (9,937)	$ (15,017)	$ 5,080
Natural gas	10,681	2,423	8,258
Foreign currency	18,858	38,981	(20,123)
Interest rate	(9,667)	(379)	(9,288)
Total	$ 9,935	$ 26,008	$ (16,073)

(1) Realized gain on financial derivative contracts represents actual cash settlement or receipts under the financial derivative contracts.

(2) Unrealized gain (loss) on financial derivative contracts represents the change in fair value of the financial derivative contracts during the period.

The total gain on financial derivative contracts for the year ended December 31, 2010 was $9.9 million, as compared to a gain of $26.0 million in the year ended December 31, 2009. This includes realized gains of $48.1 million and unrealized mark-to-market losses of $38.2 million for the year ended December 31, 2010, as compared to $80.8 million in realized gains and $54.8 million in unrealized mark-to-market losses for the same period in 2009. The realized gain of $48.1 million for the year ended December 31, 2010 is due to the settlement of gains on favorable foreign currency and commodity derivative contracts. The unrealized mark-to-market losses of $38.2 million for the year ended December 31, 2010 is due to settlement of previously unrealized gains from foreign currency swaps and commodity derivatives and a decrease in floating interest rates in the year ended December 31, 2010 as compared to December 31, 2009.

Details of the risk management contracts in place as at December 31, 2010, and the accounting treatment of the Company's financial instruments are disclosed in note 17 to the consolidated financial statements as at and for the year ended December 31, 2010.

Operating Expenses

($ thousands except for % and per boe)	Years Ended December 31 2010	2009	*Change*
Operating expenses	$ 171,740	$ 163,183	*5%*
Operating expenses per boe	$ 10.62	$ 10.83	*(2%)*

Operating expenses for the year ended December 31, 2010 increased to $171.7 million from $163.2 million for the same period of 2009 due to an increase in production volumes. Operating expenses were $10.62 per boe for the year ended December 31, 2010, as compared to $10.83 per boe for the same period in 2009. For the year ended

December 31, 2010, operating expenses were $10.66 per boe of light oil, NGL and natural gas and $10.60 per barrel of heavy oil, as compared to $11.70 and $10.24, respectively, for the year ended December 31, 2009.

Transportation and Blending Expenses

	Years Ended December 31		
($ thousands except for % and per boe)	2010	2009	*Change*
Blending expenses	$ 141,448	$ 110,772	*28%*
Transportation expenses[1]	47,143	48,582	*(3%)*
Total transportation and blending expenses	$ 188,591	$ 159,354	*18%*
Transportation expense per boe[1]	$ 2.92	$ 3.22	*(9%)*

(1) Transportation expenses per boe are before the purchase of blending diluent.

Transportation and blending expenses for year ended December 31, 2010, were $188.6 million, as compared to $159.4 million for the year ended December 31, 2009.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex mainly purchases condensate from industry producers as the blending diluent to facilitate the marketing of its heavy oil. In the year ended December 31, 2010, the blending cost was $141.4 million for the purchase of 4,557 bbl/d of condensate at $85.05 per barrel, as compared to $110.8 million for the purchase of 4,240 bbl/d at $71.58 per barrel for the same period last year. The cost of blending diluent is effectively recovered in the sale price of a blended product.

Transportation expenses before blending costs were $2.92 per boe for the year ended December 31, 2010, as compared to $3.22 per boe for the same period of 2009. Transportation expenses were $0.85 per boe of light oil, NGL and natural gas and $4.05 per barrel of heavy oil in 2010, as compared to $0.79 and $4.88, respectively, for the same period in 2009. The decrease in transportation cost per barrel of heavy oil was primarily attributable to the reduced use of long-haul trucking at Seal.

Operating Netback

	Years Ended December 31		
($ per boe except for % and volume)	2010	2009	*Change*
Sales volume (boe/d)	44,305	41,291	*7%*
Operating netback[1]**:**			
Sales price[2]	$ 53.39	$ 45.00	*19%*
Less:			
Royalties	10.04	8.67	*16%*
Operating expenses	10.62	10.83	*(2%)*
Transportation expenses	2.92	3.22	*(9%)*
Operating netback before financial derivative contracts	$ 29.81	$ 22.28	*34%*
Financial derivative contract gains[3]	2.98	5.36	*(44%)*
Operating netback after financial derivative contracts	$ 32.79	$ 27.64	*19%*

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Sales price is shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial derivative contracts reflect realized financial derivative contract gains (losses) only.

General and Administrative Expenses

	Years Ended December 31		
($ thousands except for % and per boe)	2010	2009	Change
General and administrative expenses	$ 39,774	$ 35,006	14%
General and administrative expenses per boe	$ 2.46	$ 2.32	6%

General and administrative expenses for the year ended December 31, 2010, increased to $39.8 million from $35.0 million for the same period in 2009. This increase consists of costs relating to our Income Tracking Unit Plan of $1.9 million, $1.2 million in tax indemnification payments relating to our Trust Unit Rights Incentive Plan (compared to $3.4 million in the year ended December 31, 2009), higher operating overhead recoveries in the year ended 2009 due to retroactive recoveries, as well as increased rent related to head office relocation and costs related to the Corporate Conversion as compared to the year ended December 31, 2009. Excluding the tax indemnification payments identified above, general and administrative expenses for the year ended December 31, 2010, would have been $2.39/boe (year ended December 31, 2009 – $2.10/boe).

Unit-Based Compensation Expense

For the year ended December 31, 2010, compensation expense related to our Trust Unit Rights Incentive Plan was $8.3 million, an increase of 30% compared to $6.4 million for the same period in 2009. This increase is the result of higher average fair values assigned to new unit rights granted.

Compensation expense associated with our Trust Unit Rights Incentive Plan is recognized in income over the vesting period of the unit rights with a corresponding increase in contributed surplus. The exercise of unit rights was recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Interest Expense

Interest expense for the year ended December 31, 2010 decreased to $26.7 million, as compared to $32.7 million in the same period in 2009. The decrease was attributable to a lower effective interest rate on long-term debt due to the issuance on August 26, 2009 of $150 million of 9.15% Series A senior unsecured debentures and the retirement on September 25, 2009 of US$179.7 million of 9.625% senior subordinated notes and US$0.2 million of 10.5% senior subordinated notes, offset by a higher bank loan balance and prime lending rate in 2010 compared to 2009.

Financing Charges

Financing charges for the year ended December 31, 2010 were $1.6 million, as compared to $5.5 million for the year ended December 31, 2009. This decrease is due to lower fees associated with our revolving credit facilities and the issuance of $150.0 million of 9.15% Series A senior unsecured debentures on August 26, 2009.

Foreign Exchange

	Years Ended December 31		
($ thousands)	2010	2009	Change
Unrealized foreign exchange gain	$ (8,999)	$ (2,623)	$ (6,376)
Realized foreign exchange gain	(149)	(20,201)	20,052
Total gain	$ (9,148)	$ (22,824)	$ 13,676

Foreign exchange gain in the year ended December 31, 2010 was $9.1 million, as compared to a gain of $22.8 million in the year ended 2009. This gain was comprised of an unrealized foreign exchange gain of $9.0 million and a realized foreign exchange gain of $0.1 million. The unrealized gains of $9.0 million in 2010 and $2.6 million in 2009 were due to the translation of the US$180 million portion of our bank loan as the CAD/USD foreign exchange rates strengthened at December 31, 2010 (as compared to December 31, 2009) and December 31, 2009 (as compared to December 31, 2008). The current year realized gain relates to US$ denominated financial derivative contract gains and from day-to-day US$ denominated transactions, as compared to the prior year gain of $20.2 million which was mainly due to redemption of the US$ senior subordinated notes in September 2009.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the year ended December 31, 2010 increased to $271.0 million from $237.2 million for the same period in 2009. On a sales-unit basis, the provision for the year ended December 31, 2010, was $16.76 per boe, as compared to $15.74 per boe for the same period in 2009.

Taxes

Current tax expense for the year ended December 31, 2010 was $8.5 million, $2.9 million lower than the year ended 2009. The lower current tax expense is due to an out of period adjustment of $4.0 million related to Saskatchewan resource surcharge tax.

For the year ended December 31, 2010, future tax recovery totaled $32.1 million, as compared to a future tax recovery $30.5 million for the year ended 2009. The increase in future tax recovery is primarily due to higher distributed earnings in the current year, offset by higher operating income.

As at December 31, 2010, future income tax liability was $15.4 million (December 31, 2009 – $186.6 million). In May 2010, Baytex acquired a number of private entities for use in its internal financing structure for approximately $38.0 million. The transaction resulted in the recognition of future income tax asset of $147.8 million with a corresponding deferred credit of $109.8 million. This credit reflects the difference between the future income tax asset recognized upon the completion of this transaction and the cash paid. This credit will be amortized on the same basis as the related future income tax asset.

Tax Pools

During 2010 and 2009, Baytex was organized as a Mutual Fund Trust for Canadian income tax purposes. Partially as a result of tax deductions taken for distributions paid to unitholders in 2010 and 2009, no material Canadian cash tax expense, other than the Saskatchewan resource surcharge, was payable by Baytex. Following the conversion from a trust structure to a corporate legal form on December 31, 2010, Baytex will not be entitled to a deduction from Canadian taxable income for its distributions, nor will a deduction be available for future dividends. As such it is likely that cash income tax expense attributable to our Canadian operations will be higher in future years than it was during the time we operated as a trust. Baytex has accumulated the Canadian and U.S. tax pools as noted in the table below which will be available to reduce future taxable income. Our cash income tax liability is dependant upon many factors, including the prices at which we sell our production, available income tax deductions, and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook and a projected production and cost levels, Baytex does not expect to become liable for Canadian income tax, other than the Saskatchewan resource surcharge, until 2012. The income tax pools detailed below are deductible at various rates as prescribed by law.

($ thousands)	December 31, 2010	December 31, 2009
Canadian Tax Pools		
Canadian oil and gas property expenditures	$ 286,879	$ 299,220
Canadian development expenditures	234,836	189,791
Canadian exploration expenditures	9,716	–
Undepreciated capital costs	236,192	241,071
Non-capital losses	773,396	19,470
Finance costs	10,334	169
Total Canadian tax pools	$1,551,353	$ 749,721
U.S. Tax Pools		
Taxable depletion	$ 117,765	$ 148,031
Intangible drilling costs	35,000	9,182
Tangibles	13,048	3,686
Non-capital losses	64,541	4,178
Total U.S. tax pools	$ 230,354	$ 165,077

Net Income

Net income for the year ended December 31, 2010, was $177.6 million, as compared to net income of $87.6 million for the year ended December 31, 2009. Revenues, net of royalties, increased $183.8 million or 28% in the year ended December 31, 2010, as compared to the same period in 2009. In addition, lower interest expense and financing charges in 2010 also increased net income by $6.0 million and $3.9 million, respectively, in the year ended December 31, 2010, as compared to same period in 2009. These increases were partially offset by operating costs of $8.6 million, foreign exchange of $13.7 million and depletion and accretion of $33.8 million for the year ended December 31, 2010, as compared to the same period in 2009.

Other Comprehensive Loss

The Company's foreign operations are considered to be "self-sustaining operations", financially and operationally independent. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date, while revenues and expenses are translated using the average exchange rate for the year ended December 31, 2010. Translation gains and losses are deferred and included in other comprehensive income in shareholders' capital and are recognized in net income when there has been a reduction in the net investment.

This change was adopted prospectively on January 1, 2009 resulting in a currency translation adjustment of $15.4 million upon adoption with a corresponding increase in petroleum and natural gas properties. The reduction of $19.3 million for 2009 plus the reduction of $10.7 million in the year ended December 31, 2010 resulted in a balance of $14.6 million in accumulated other comprehensive loss at December 31, 2010.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DISTRIBUTIONS OR DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. Payout ratio is calculated as cash distributions (net of participation in the Distribution Reinvestment Plan ("DRIP")) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate its ability to generate the cash flow necessary to fund dividends and capital investments.

The following table reconciles cash flow from operating activities (a Canadian GAAP measure) to funds from operations (a non-GAAP measure):

	Years Ended	
($ thousands except for %)	**December 31, 2010**	December 31, 2009
Cash flow from operating activities	**$ 441,438**	$ 303,162
Change in non-cash working capital	**9,967**	27,878
Asset retirement expenditures	**2,778**	1,146
Funds from operations	**$ 454,183**	$ 332,186
Cash distributions declared, net of DRIP	**$ 189,824**	$ 137,601
Payout ratio	**42%**	41%

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the petroleum and natural gas industry, due to the nature of reserve 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 petroleum and natural gas assets increase significantly, it is possible that Baytex would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that Baytex will be able to maintain current production levels in future periods.

Cash distributions declared, net of DRIP participation, of $189.8 million for the year ended December 31, 2010 were funded through funds from operations of $454.2 million. The following table compares cash distributions to cash flow from operating activities and net income:

	Years Ended	
($ thousands except for %)	**December 31, 2010**	December 31, 2009
Cash flow from operating activities	**$ 441,438**	$ 303,162
Cash distributions declared, net of DRIP	**189,824**	137,601
Excess of cash flow from operating activities over cash distributions declared, net of DRIP	**$ 251,614**	$ 165,561
Net income	**$ 177,631**	$ 87,574
Cash distributions declared, net of DRIP	**189,824**	137,601
Shortfall of net income over cash distributions declared, net of DRIP	**$ (12,193)**	$ (50,027)

It is Baytex's long-term operating objective to substantially fund cash dividends and capital expenditures for exploration and development activities through funds from operations. Future production levels are highly dependent 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 dividends. During periods of lower commodity prices or periods of higher capital spending, it is possible that funds from operations will not be sufficient to fund both cash dividends and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

As at December 31, 2010, Baytex had approximately $246.2 million in available undrawn credit facilities to fund any such shortfall. As a result of our semi-annual borrowing base review, and following the completion of an acquisition, subsequent agreements effective January 1, 2011 and February 17, 2011 provided an additional $100.0 million in available credit facilities.

For the year ended December 31, 2010, the Company's net income was less than cash distributions declared (net of DRIP) by $12.2 million, with net income reduced by $263.8 million for non-cash items. Non-cash items such as depletion, depreciation and accretion may not be 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.

LIQUIDITY AND CAPITAL RESOURCES

We regularly review our liquidity sources as well as our exposure to counterparties, and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business. We periodically review the financial capacity of our counterparties and, in certain circumstances, we will seek enhanced credit protection from a counterparty.

($ thousands)	**December 31, 2010**	December 31, 2009
Bank loan	**$ 303,773**	$ 265,088
Convertible debentures	**–**	7,736
Long-term notes	**150,000**	150,000
Working capital deficiency	**48,417**	51,452
Total monetary debt	**$ 502,190**	$ 474,276

At December 31, 2010, total monetary debt was $502.2 million, as compared to $474.3 million at December 31, 2009. Bank borrowings at December 31, 2010 were $303.8 million, as compared to total credit facilities of $550.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd ("Baytex Energy"), has established credit facilities with a syndicate of financial institutions. The credit facilities consist of an operating loan and a 364-day revolving loan. In June 2010, Baytex Energy reached agreement with its lending syndicate to amend its revolving credit facilities to increase the amount of the facilities to $550 million (from $515 million), extend the revolving period to June 2011 and add a one-year term out following the revolving period. In the event that the revolving period is not extended by June 2011, all amounts then outstanding under the credit facilities will be payable in June 2012. 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 or LIBOR rates, plus applicable margins. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of our assets. The weighted average interest rate on our bank loan for the year ended December 31, 2010 was 4.60% (December 31, 2009 – 4.42%).

A subsequent agreement effective January 1, 2011 was reached between Baytex Energy and its lending syndicate to increase the amount of the credit facilities to $625 million (from $550 million), to decrease its margins on advances based on the prime lending rate, bankers' acceptance rates or LIBOR rates and to decrease standby fees. The credit facilities were further increased to $650 million (from $625 million) effective February 17, 2011.

The credit facilities were arranged pursuant to an agreement with a syndicate of financial institutions. A copy of the credit agreement and related amendments are accessible on the SEDAR website at www.sedar.com (filed on March 28, 2008, September 15, 2008, July 9, 2009, August 14, 2009, October 5, 2009, July 15, 2010, August 31, 2010, January 10, 2011 and February 24, 2011).

Subsequent to year-end, on February 17, 2011, Baytex issued US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. Net proceeds of this issue were used to repay a portion of the amount drawn in Canadian currency on our credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

Pursuant to various agreements with our lenders, we are restricted from making dividends to shareholders where the dividend would or could have a material adverse effect on us or our subsidiaries' ability to fulfill our respective obligations under the Series A or Series B senior unsecured debentures and the credit facilities.

Baytex believes that funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders 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. The level of dividend is also discretionary, and the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Capital Expenditures

Capital expenditures are summarized as follows:

	Years Ended December 31	
($ thousands)	2010	2009
Land	$ 17,908	$ 13,514
Seismic	569	2,222
Drilling and completion	157,464	113,959
Equipment	61,200	26,164
Other	(162)	1,185
Total exploration and development	$ 236,979	$ 157,044
Corporate acquisition	40,914	–
Property acquisitions	24,763	133,155
Property dispositions	(19,033)	(78)
Total oil and gas expenditures	283,623	$ 290,121
Corporate assets	8,457	7,050
Total capital expenditures	$ 292,080	$ 297,171

Shareholders' Equity

On December 31, 2010, all of the outstanding trust units of the Trust were exchanged for common shares of Baytex on a one-for-one basis in connection with the Corporate Conversion.

Baytex is authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. Baytex establishes the rights and terms of preferred shares upon issuance. As at March 1, 2011, the Company had 114,709,978 common shares and no preferred shares issued and outstanding.

Off Balance Sheet Arrangements

Baytex is not party to any contractual arrangement under which a non-consolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. Baytex has no obligation under financial instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company, or engages in leasing, hedging or research and development services with the Company.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations in an ongoing manner. A significant portion of these obligations will be funded through funds from operations. These obligations as of December 31, 2010, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-2 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	**$ 179,269**	$ 179,269	$ –	$ –	$ –
Distributions payable to unitholders	**22,742**	22,742	–	–	–
Bank loan(1)	**303,773**	–	303,773	–	–
Long-term debt(2)	**150,000**	–	–	–	150,000
Operating leases	**55,645**	5,667	11,435	12,284	26,259
Processing and transportation agreements	**4,207**	3,175	1,006	26	–
Total	**$ 715,636**	$ 210,853	$ 316,214	$ 12,310	$ 176,259

(1) *The bank loan is a 364-day revolving loan with a one year term-out following the 364-day revolving period with the ability to extend the term. Unless extended, the revolving period will end on June 27, 2011 with all amounts to be re-paid by June 27, 2012.*

(2) *Principal amount of instruments.*

Baytex also has on-going 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.

FINANCIAL INSTRUMENTS 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 Company's control. Included in these risks are the uncertainty of finding new reserves, fluctuations in 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 Baytex competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing Baytex 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. Baytex's ability to increase its production, revenues and funds from operations 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 petroleum 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 Company's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of members of the Board of Directors of Baytex (the "Board"), 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 Baytex is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Company'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, Baytex 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 of the risk management program is to decrease exposure to market volatility and ensure the Company's ability to finance its dividends and capital program.

Baytex'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 borrowings. The related foreign exchange gains and losses are included in net income.

Baytex is exposed to changes in interest rates as the Company's credit facilities are based on the lenders' prime lending rate, bankers' acceptance rates or LIBOR rates.

Details of the risk management contracts in place as at December 31, 2010 and the accounting for the Company's financial instruments are disclosed in note 17 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2010 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

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 Company. The financial and operating results of Baytex incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of petroleum and natural gas reserves that Baytex expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

Baytex has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Future Accounting Changes

In 2006, Canada's Accounting Standards Board (the "AcSB") ratified a strategic plan to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") by 2011 for publicly accountable entities. On February 13, 2008 the AcSB confirmed that IFRS would replace Canadian GAAP for public companies beginning January 1, 2011. As a result, Baytex will issue financial statements under IFRS in 2011.

Convergence of Canadian GAAP with IFRS

IFRS replaces Canadian GAAP for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises are required to prepare financial statements in accordance with IFRS. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of 2010 amounts reported by Baytex, including the opening balance sheet as at January 1, 2010. Baytex expects that IFRS will not have a major impact on the Company's operations or strategic decisions.

Management continues to monitor new IFRS and amendments to existing IFRS that may impact the adoption of IFRS by Baytex in 2011Our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011.

Management has not yet finalized the quantification of the impact on Baytex's 2010 financial statements. Baytex continues to draft IFRS compliant financial statements and develop the corresponding accounting entries to comply with the proposed IFRS accounting policies. The various accounting policy choices and results remain subject to further review by management. The IFRS implementation will continue into 2011 and will conclude with the issuance of the first quarter financial statements of 2011. The Company's external auditors are expected to continue to review draft IFRS accounting policies and the IFRS 2010 comparative periods during the first few months of 2011.

Management expects to apply the following accounting policies under IFRS. The adjustments and resulting IFRS amounts are unaudited and subject to change.

First-Time Adoption of IFRS

IFRS 1, "First-Time Adoption of International Financial Reporting Standards", provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Baytex expects to apply the following exemptions:

Property, Plant and Equipment, ("PP&E") – IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production ("D&P") phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date.

Asset retirement obligations – Decommissioning provisions, included in the cost of PP&E, are measured as at January 1, 2010 in accordance with International Accounting Standards ("IAS") 37, "Provisions, Contingent Liabilities and Contingent Assets", and the difference between that amount and the carrying amount of those liabilities at January 1, 2010 determined under Canadian GAAP are recognized directly in deficit.

Business combinations – IFRS 1 permits the use of IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based payments – IFRS 1 provides an exemption on IFRS 2 ("Share-Based Payments") to liabilities arising from share-based payment transactions that were settled before the Company's transition date to IFRS.

Cumulative translation differences – An option is available to deem cumulative translation differences on all foreign operations as zero at the date of transition. Under Canadian GAAP, accumulated other comprehensive loss amounts are composed entirely of currency translation adjustments on self-sustaining foreign operations. Under IFRS, the Company has elected to deem cumulative translation differences as $nil at January 1, 2010. At January 1, 2010, this has resulted in an increase in other comprehensive income and deficit of $3.9 million.

Borrowing Costs – IFRS 1 allows application of the IAS 23 ("Borrowing Costs") to borrowing costs related to qualifying assets for which the commencement date for capitalization is on or after January 1, 2010.

Leases – International Financial Reporting Interpretations Committee 1, "Determining whether an Arrangement contains a Lease" transition rules allow determination of whether any existing arrangement at January 1, 2010 contains a lease on the basis of the facts and circumstances existing at that date.

Estimated Impact on Reported Financial Position

The following information summarizes the key transitional adjustments required for the January 1, 2010 opening balance sheet on adoption of IFRS. These amounts will be impacted by the deferred tax effect of the IFRS adjustments.

(thousands of Canadian dollars) (unaudited)	Canadian GAAP	IFRS Adjustments	IFRS
Current assets	179,539	(1,371)	178,168
Non-current assets	1,704,466	1,371	1,705,837
	1,884,005	–	1,884,005
Current liabilities	486,324	(1,329)	484,995
Non-current liabilities	385,684	161,834	547,518
Unitholders' Equity	1,011,997	(160,505)	851,492
	1,884,005	–	1,884,005

Exploration and Evaluation ("E&E") expenditures – On transition to IFRS, Baytex will re-classify all E&E expenditures that are currently included in the PP&E balance on the consolidated balance sheet. This will consist of the book value of undeveloped land that relates to exploration properties. Baytex will initially capitalize these costs as E&E assets on the balance sheet. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.

Under the IFRS 1 election, Baytex has measured exploration and evaluation assets at the amount determined under the entity's previous GAAP resulting in $124.6 million reclassified from oil and gas properties to exploration and evaluation assets.

Depletion expense – Under Canadian GAAP depletion was calculated on a unit of production basis using proved reserves at the country level. Under IFRS, costs will be depleted on a unit of production basis at a more granular level than the country level. Baytex will calculate the depletion calculation using proved plus probable reserves at an area level.

Derecognition of D&P assets – Under Canadian GAAP, full cost accounting gains and losses were not recognized upon disposition of oil and gas assets unless such a disposition would alter the rate of depletion by 20% or more. Under IFRS, gains and losses are recognized based on the difference between the net proceeds from the disposition and carrying value.

Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash generating unit ("CGU") level using fair values of the PP&E assets. Baytex anticipates using discounted proved plus probable reserve values for impairment tests of PP&E. Under Canadian GAAP, estimated future cash flows used to assess impairments are not discounted. As such, impairment losses may be recognized earlier under IFRS than under Canadian GAAP. Impairment losses are reversed under IFRS when there is an increase in the recoverable amount.

Baytex has allocated the property, plant and equipment amount recognized under Canadian GAAP as at January 1, 2010 to the assets at CGU level using reserve values calculated using the discounted net cash flows. There is no change in the overall net book value of our PP&E as no IFRS impairments are expected at January 1, 2010.

Decommissioning provisions – Under IFRS, Baytex will use a risk-free interest rate to discount the estimated fair value of its asset retirement obligations and the related PP&E. Under Canadian GAAP, the Company uses a credit-adjusted interest rate. A lower discount rate will increase the asset retirement obligation liability. In addition, under IFRS, asset retirement obligations are measured using the best estimate of the expenditure to be incurred and requires the use of current discount rates at each re-measurement date with the corresponding adjustment to the cost of the related PP&E. Existing liabilities under Canadian GAAP are not re-measured using current discount rates.

Under Canadian GAAP, the Company's decommissioning provision is recorded using the credit-adjusted risk free rate of 8.0%. Under IFRS, the Company's decommissioning provision is recorded using the risk-free rate of 4.0%. Under IFRS, an additional liability of $87.3 million has been recognized with an offsetting charge to deficit at January 1, 2010.

Unit-based compensation – Under IFRS, prior to the conversion to a corporation, the obligation associated with the Trust Unit Rights Incentive Plan is considered a liability and the fair value of the liability is re-measured at each reporting date and at settlement date. Any changes in fair value are recognized in profit or loss for the period. Under Canadian GAAP, the obligation associated with the Trust Unit Rights Incentive Plan is considered to be equity-based and the related unit-based compensation is calculated using the binomial-lattice model to estimate the fair value of the outstanding rights at grant date. The exercise of unit rights is recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus. Re-measuring the fair value of the obligation each reporting period for periods prior to the conversion to a corporation will increase the unit-based payment liability, unitholders' capital and compensation expense recognized. The modification that converts the outstanding rights to acquire trust units to rights to acquire common shares in connection with the Corporate Conversion effectively changes the related classification to equity-settled. The expense recognized from the date of modification over the remainder of the vesting period is determined based on the fair value of the reclassified equity awards at the date of the modification.

At January 1, 2010 under IFRS, an additional unit-based payment liability of $69.4 million and a decrease of $20.4 million in contributed surplus is offset by a $49.0 million charge to deficit.

Convertible debentures – Under IFRS, the conversion feature of the convertible debentures has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the instrument are recognized in the statement of comprehensive income. If the debentures are converted to trust units, the fair value of the conversion feature under financial derivative liability is reclassified to unitholders' or shareholders' capital along with the principal amounts converted. Under Canadian GAAP, the convertible debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' or shareholders' equity. The debt portion accreted up to the principal balance at maturity. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity were reclassified to unitholders' capital along with principal amounts converted.

At January 1, 2010 under IFRS, an additional financial derivative liability of $7.4 million, an increase of $33.4 million in unitholders' equity, a decrease of $0.4 million in conversion feature of convertible debentures has been recognized with the offsetting $40.4 million increase in deficit.

Trust Units Classification – IFRS prescribes the principles for determining the classification of the financial instruments as debt or equity. Under Canadian GAAP Baytex's trust units were considered permanent equity and included within unitholders' capital. Under IFRS, the trust units are considered puttable financial instruments however a specific exemption for trust units specifies they are classified as permanent equity within unitholders' capital. Although Baytex converted to a corporation on December 31, 2010, Baytex was required to determine if it met the criteria for this exemption to conclude on the appropriate presentation for the pre-conversion period. Baytex has assessed that the application of IFRS principles and standards to Baytex's trust units results in their treatment as equity.

Income taxes – Under IFRS, future income taxes are required to be presented as non-current deferred tax assets and liabilities. In transitioning to IFRS, the Company's deferred tax liability will be impacted by the tax effects resulting from the IFRS adjustments.

Internal Controls Over Financial Reporting

Along with review of the accounting policy choices and analysis, assessments are also made to determine the changes required to internal controls over financial reporting. The internal controls documentation will continue to be updated to reflect changes in accounting polices and appropriate additional controls and procedures for reporting under IFRS.

Disclosure controls and procedures

Throughout the transition process, Baytex will be assessing stakeholders' information requirements to ensure that appropriate and timely information is provided once available. Management anticipates disclosure in investor presentations and in shareholder publications during 2011 to explain differences between the historical Canadian GAAP statements and the IFRS statements.

Information Technology Systems

The most significant information systems challenges for the IFRS conversion were ensuring the Company had the ability to track its IFRS adjustments in the year of transition and that new IFRS reports could be produced to facilitate the preparation of IFRS financial statements. The Company has successfully tested its ability to track IFRS adjustments for its 2010 comparative periods and has successfully implemented the modifications required to existing and new reports to facilitate the preparation of the increased note disclosure required under IFRS.

Baytex is unable to quantify the full impact on the financial statements of adopting IFRS; however the company has disclosed certain expectations above based on information known to date. Certain items may be subject to change based on facts and circumstances as they arise after the date of this MD&A.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share or trust unit amounts)	2010	2009	2008
Petroleum and natural gas sales	**$ 1,005,136**	$ 789,743	$ 1,159,718
Net income(1)	**$ 177,631**	$ 87,574	$ 259,894
Per common share or trust unit – basic(1)	**$ 1.59**	$ 0.83	$ 2.83
Per common share or trust unit – diluted(1)	**$ 1.54**	$ 0.82	$ 2.74
Total assets	**$ 2,047,212**	$ 1,884,005	$ 1,812,333
Total other long-term financial liabilities	**$ 453,773**	$ 150,000	$ 227,468
Cash distributions declared per common share or trust unit	**$ 2.18**	$ 1.56	$ 2.64

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

Overall production for 2010 was 44,341 boe/d which represented a 7% increase from 41,382 boe/d in 2009 and a 10% increase from 40,239 boe/d in 2008. Average wellhead prices net of blending costs received were $53.39 per boe during 2010, $45.00 per boe during 2009 and $65.66 per boe during 2008.

FOURTH QUARTER 2010

For a discussion and analysis of our operating and financial results for the three months ended December 31, 2010, please see our Management's Discussion and Analysis for the three months and year ended December 31, 2010 dated March 7, 2011, which is incorporated by reference into this MD&A and is accessible on SEDAR at www.sedar.com.

2011 GUIDANCE

Baytex has set a 2011 exploration and development capital budget of $325 million designed to generate production levels at an average annual rate of 49,000 to 50,000 boe/d, including production from our heavy oil acquisition which closed on February 3, 2011. Approximately 60% of our 2011 capital program will be directed to our heavy oil operations, with the single largest project being horizontal-well cold development at Seal in the Peace River Oil Sands. We also plan to complete our first 10-well commercial thermal module at Seal, with start-up scheduled before the end of 2011.

During 2011, we plan increased development in our cold drilling program in the Lloydminster area where, for the first time, horizontal wells will constitute the majority of wells drilled. In addition, the 2011 heavy oil program provides for two new steam assisted gravity drainage well pairs at Kerrobert in Saskatchewan. The balance of our capital program will be directed primarily towards light oil development, with the two largest projects being the Bakken/Three Forks in North Dakota and the Viking in southeast Alberta. Other development projects include light oil development in the Viking in southwest Saskatchewan and the Cardium in central Alberta.

We viewed 2010 as the transition year for our shift from a predominantly income-focused model as a trust to a growth-and-income model in the new corporate era. Our 2011 capital program completes this transition to the growth-and-income model. Based on the high end of the production guidance ranges for 2011, the 2011 plan reflects an organic production growth rate of approximately 8%. Our 2011 production mix is forecast to be approximately 66% heavy oil, 17% light oil and natural gas liquids and 17% natural gas, based on a 6:1 gas-to-oil equivalency.

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.

Climate Change Regulation

The Government of Canada ratified the Kyoto Protocol in 2002, calling for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels by 2012. In December 2009, representatives of approximately 170 countries meet in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The Copenhagen negotiations resulted in the Copenhagen Accord, a non-binding political accord which reinforced the Kyoto Protocol's commitment to reducing greenhouse gas emissions. In response to the Copenhagen Accord, the government of Canada revised its emissions reduction goals and now aims to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. Despite the commitments made under the Kyoto Protocol and the Copenhagen Accord, no federal legislation has been implemented to regulate the emission of greenhouse gases and the Government of Canada has indicated that it will delay the implementation of climate change legislation and regulations in order to ensure consistency with the approach ultimately taken by the United States with respect to greenhouse gas emissions.

There has been much public debate with respect to Canada's ability to meet these targets and the Government of Canada's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The implementation of strategies for reducing greenhouse gases, whether to meet the goals of the Kyoto Protocol, the Copenhagen Accord or otherwise, could have a material impact on the nature of oil and natural gas operations, including those of Baytex. 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 its operations and financial condition.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2010 under the Industry Conditions section.

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 Federal 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.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2010, an evaluation was conducted of the effectiveness of the Baytex's "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) by management, with the participation of the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Baytex's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Baytex files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Baytex's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Baytex. "Internal control over financial reporting" (as defined in the United States by Rules 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) 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 has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. 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 Company's internal control over financial reporting was effective as of December 31, 2010. The effectiveness of the Baytex's internal control over financial reporting as of December 31, 2010 has been audited by Deloitte & Touche LLP, as reflected in their report for 2010.

No changes were made to our internal control over financial reporting during the year ended December 31, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of The Company's future plans and operations, certain statements 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"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. 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: crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our business strategies, plans and objectives; our ability to utilize our tax pools to reduce or potentially eliminate our taxable income for the initial period post-conversion; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash dividends and capital program; the timing of funding our financial obligations; the existence, operation, and strategy of our risk management program; the impact of the adoption of new accounting standards on our financial results; and the impact of the adoption of IFRS on our financial position and results of operations; our exploration and development capital expenditures for 2011 and the allocation thereof; our average production rate for 2011; development plans for our properties, including the number of wells to be drilled and the timing of completing a 10-well thermal module at our Seal heavy oil resource play; our organic production growth rate in 2011; and our 2011 production mix. 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 dividends 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: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2010, 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. is responsible for establishing and maintaining adequate internal control over financial reporting over the Company. Under the supervision of our Chief Executive Officer and our Chief Financial Officer, we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2010, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010 has been audited by Deloitte & Touche LLP, the Company's Independent Registered Chartered Accountants, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2010.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Corp. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Chartered Accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of Deloitte & Touche LLP and reviews their fees. The Independent Registered Chartered Accountants have access to the Audit Committee without the presence of management.

Anthony W. Marino
President and Chief Executive Officer
Baytex Energy Corp.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Corp.

March 15, 2011

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Baytex Energy Corp.:

We have audited the accompanying consolidated financial statements of Baytex Energy Corp. (formerly Baytex Energy Trust) and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income and comprehensive income, deficit, and cash flows for the years then ended, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Baytex Energy Corp. and subsidiaries as at December 31, 2010 and 2009 and the results of their operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Canada
March 15, 2011

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Baytex Energy Corp.

We have audited the internal control over financial reporting of Baytex Energy Corp. (formerly Baytex Energy Trust) and subsidiaries (the "Company") as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as at and for the year ended December 31, 2010 of the Company and our report dated March 15, 2011 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Calgary, Canada
March 15, 2011

Independent Registered Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at	December 31, 2010	December 31, 2009
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Cash	$ –	$ 10,177
Accounts receivable	151,792	137,154
Crude oil inventory	1,802	1,384
Future income tax asset (note 14)	5,480	1,371
Financial derivative contracts (note 17)	13,921	29,453
	172,995	179,539
Future income tax asset (note 14)	150,190	418
Financial derivative contracts (note 17)	2,622	2,541
Petroleum and natural gas properties (note 5)	1,683,650	1,663,752
Goodwill	37,755	37,755
	$ 2,047,212	$ 1,884,005
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 179,269	$ 180,493
Distributions payable to unitholders	22,742	19,674
Bank loan (note 6)	–	265,088
Convertible debentures (note 8)	–	7,736
Future income tax liability (note 14)	3,756	8,683
Financial derivative contracts (note 17)	20,312	4,650
	226,079	486,324
Bank loan (note 6)	303,773	–
Long-term debt (note 7)	150,000	150,000
Deferred credit (note 14)	109,800	–
Asset retirement obligations (note 9)	52,373	54,593
Future income tax liability (note 14)	167,302	179,673
Financial derivative contracts (note 17)	8,859	1,418
	1,018,186	872,008
SHAREHOLDERS'/UNITHOLDERS' EQUITY		
Shareholders' capital (note 10)	1,390,034	–
Unitholders' capital (note 10)	–	1,295,931
Conversion feature of convertible debentures (note 8)	–	374
Contributed surplus (note 11)	20,131	20,371
Accumulated other comprehensive loss (note 12)	(14,607)	(3,899)
Deficit	(366,532)	(300,780)
	1,029,026	1,011,997
	$ 2,047,212	$ 1,884,005

Commitments and contingencies (note 18)
Subsequent events (note 20)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Years Ended December 31	2010	2009
(thousands of Canadian dollars, except per common share and per trust unit amounts)		
Revenue		
Petroleum and natural gas	$ 1,005,136	$ 789,743
Royalties	(162,332)	(130,705)
Gain on financial derivative contracts (note 17)	9,935	26,008
	852,739	685,046
Expenses		
Operating	171,740	163,183
Transportation and blending	188,591	159,354
General and administrative	39,774	35,006
Unit-based compensation (note 11)	8,344	6,443
Interest (note 15)	26,670	32,685
Financing charges	1,643	5,496
Foreign exchange gain (note 16)	(9,148)	(22,824)
Depletion, depreciation and accretion	271,042	237,216
	698,656	616,559
Income before income taxes	154,083	68,487
Income tax (recovery) expense (note 14)		
Current	8,512	11,370
Future	(32,060)	(30,457)
	(23,548)	(19,087)
Net income	$ 177,631	$ 87,574
Other comprehensive loss		
Foreign currency translation adjustment (note 12)	(10,708)	(3,899)
Comprehensive income	$ 166,923	$ 83,675
Net income per common share or trust unit (note 13)		
Basic	$ 1.59	$ 0.83
Diluted	$ 1.54	$ 0.82
Weighted average common shares or trust units (note 13)		
Basic	111,450	104,894
Diluted	115,520	107,246

CONSOLIDATED STATEMENTS OF DEFICIT

Years Ended December 31	2010	2009
(thousands of Canadian dollars)		
Deficit, beginning of year	$ (300,780)	$ (224,314)
Net income	177,631	87,574
Distributions to unitholders	(243,383)	(164,040)
Deficit, end of year	$ (366,532)	$ (300,780)

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(thousands of Canadian dollars)*	2010	2009
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 177,631	$ 87,574
Items not affecting cash:		
Unit-based compensation (note 11)	8,344	6,443
Unrealized foreign exchange gain (note 16)	(8,999)	(2,623)
Depletion, depreciation and accretion	271,042	237,216
Accretion on debentures and notes (notes 7 and 8)	31	2,908
Unrealized loss on financial derivative contracts (note 17)	38,194	54,810
Future income tax recovery	(32,060)	(30,457)
Realized foreign exchange gain on redemption of long-term debt (notes 7 and 16)	–	(23,685)
	454,183	332,186
Change in non-cash working capital (note 16)	(9,967)	(27,878)
Asset retirement expenditures (note 9)	(2,778)	(1,146)
	441,438	303,162
Financing activities		
Payments of distributions	(188,615)	(136,409)
Increase in bank loan	48,045	64,181
Repayment of convertible debentures (note 8)	(341)	–
Redemption of long-term debt (note 7)	–	(196,411)
Proceeds from issuance of long-term debt (note 7)	–	150,000
Issuance of trust units (note 10)	26,021	135,581
Issuance costs (note 10)	–	(6,101)
	(114,890)	10,841
Investing activities		
Petroleum and natural gas property expenditures	(236,979)	(157,044)
Acquisition of petroleum and natural gas properties	(24,763)	(133,155)
Corporate acquisition (note 4)	(40,914)	–
Disposition of petroleum and natural gas properties	19,033	78
Acquisition of financing entities (note 14)	(38,000)	–
Additions of corporate assets	(8,457)	(7,050)
Change in non-cash working capital (note 16)	(5,956)	(6,587)
	(336,036)	(303,758)
Impact of foreign exchange on cash balances	(689)	(68)
Change in cash	(10,177)	10,177
Cash, beginning of year	10,177	–
Cash, end of year	$ –	$ 10,177

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2010 AND 2009

(all tabular amounts in thousands of Canadian dollars, except per common share and per trust unit amounts)

1. BASIS OF PRESENTATION AND CORPORATE CONVERSION

Baytex Energy Corp. (the "Company" or "Baytex") is a Calgary, Alberta based conventional oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States of America.

At year-end 2010, Baytex Energy Trust (the "Trust") completed a plan of arrangement under the Business Corporations Act (Alberta) pursuant to which it converted its legal structure from an income trust to a corporation (the "Arrangement"). Pursuant to the Arrangement: (i) on December 31, 2010, holders of trust units of the Trust exchanged their trust units for common shares of the Company on a one-for-one basis; and (ii) on January 1, 2011, the Trust was dissolved and terminated, with the result that the Company became the successor to the Trust. The reorganization into a corporation has been accounted for on a continuity of interest basis, and accordingly, the consolidated financial statements reflect the financial position, results of operations, and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

The consolidated financial statements include the accounts of Baytex and subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP").

The significant differences between Canadian and United States GAAP ("U.S. GAAP"), as applicable to these consolidated financial statements and notes, are described in note 21.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of Baytex and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Company's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Goodwill impairment tests involve estimates of Baytex's fair value of the net identifiable assets and liabilities annually. If the fair value is less than the book value, an impairment would be recorded. Fair value of the Company's net identifiable assets and liabilities are based on external market value and reserve estimates and the related future cash flows which are subject to measurement uncertainty.

The amounts recorded for asset retirement obligations were estimated based on Baytex'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.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Cash

Cash includes monies on deposit and short-term investments which have an initial maturity date at acquisition of not more than 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

Petroleum and Natural Gas Operations

Baytex follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test ("ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the estimated 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 estimated 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 estimated future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. 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. The test for impairment is conducted by the comparison of the net book value to the fair value of Baytex. If the fair value of the Company is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Company to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied fair value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Asset Retirement Obligations

The Company recognizes a liability at the discounted value of the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The present value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of income and comprehensive income. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet.

Joint Interests

A portion of Baytex's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

Foreign Currency Translation

Transactions completed in foreign currencies are reflected in Canadian dollars at the foreign currency exchange rates prevailing at the time of the transactions. Current assets and liabilities denominated in foreign currencies are reflected in the financial statements at the Canadian dollar equivalent at the rate of exchange prevailing at the balance sheet date. Gains and losses are included in earnings.

The foreign operations are considered to be "self-sustaining operations". As a result, the revenues and expenses are translated to Canadian dollars using average exchange rates for the period. Assets and liabilities are translated at the period-end exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders' or unitholders' equity.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser at the pipeline delivery point.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, into one of the following five categories: held-for-trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. Baytex has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash is classified as held-for-trading and is measured at fair value which equals the carrying value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities, distributions payable to unitholders, bank debt and long-term debt are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures were classified as other financial liabilities. Upon issuance, the convertible debentures were classified into equity and financial liability components on the balance sheet at their fair value. The financial liability, net of issuance costs, was accreted, which is included within interest expense over the maturity of the debentures using the effective interest rate method.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are expensed immediately.

Financial Derivative Contracts

Baytex formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. Baytex does not use financial derivatives for trading or speculative purposes. These instruments are classified as "held-for-trading" unless designated for hedge accounting. The Company has not designated any of its risk management contracts as accounting hedges. For derivative instruments that do not qualify as hedges or are not designated as hedges, the Company applies the fair value method of accounting by recording an asset or liability on the consolidated balance sheet and recognizes changes in the fair value of the instrument in the statement of Income and comprehensive income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts.

Baytex has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments. This documentation specifically ties the derivative instruments to their use and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. When specific financial instruments are executed, Baytex assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in a particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Future Income Taxes

Baytex follows the liability method of accounting for taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and tax bases of an asset or liability, using substantively enacted tax rates. Future income 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

Baytex's Trust Unit Rights Incentive Plan (the "Unit Rights Plan"), which was superseded by the Company's Common Share Rights Incentive Plan (the "Share Rights Plan") is described in note 11. The exercise price of the rights granted under the Unit Rights Plan may be reduced in future periods in accordance with the terms of the Unit Rights Plan. The Company uses the binomial-lattice model to calculate the estimated fair value of the outstanding share rights or unit rights.

Compensation expense associated with rights granted under the Unit Rights Plan is recognized in income over the vesting period of the Unit Rights Plan with a corresponding increase in contributed surplus. The exercise of unit rights is recorded as an increase in common shares or trust units with a corresponding reduction in contributed surplus.

Per Common Share and Trust Unit Amounts

Basic net income per common share or trust unit is computed by dividing net income by the weighted average number of share rights or trust units outstanding during the year. Diluted per common share or trust unit amounts reflect the potential dilution that could occur if share rights or unit rights were exercised and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of share rights or unit rights, whereby any proceeds from the exercise of share rights or unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase common shares or trust units at the average market price during the year.

3. CHANGES IN ACCOUNTING POLICIES

Future Accounting Changes

Convergence of Canadian GAAP with International Financial Reporting Standards ("IFRS")

In 2006, Canada's Accounting Standards Board (the "AcSB") ratified a strategic plan to converge Canadian GAAP with IFRS by 2011 for publicly accountable entities. On February 13, 2008, the AcSB confirmed that IFRS would replace Canadian GAAP for public companies beginning January 1, 2011. As a result, Baytex will issue financial statements under IFRS in 2011.

4. CORPORATE ACQUISITION

On May 26, 2010, Baytex Energy Ltd. ("Baytex Energy"), a wholly-owned subsidiary of Baytex, acquired all the issued and outstanding shares of a private company, a junior heavy oil producer with operational focus in east central Alberta through to west central Saskatchewan, for total consideration of $40.9 million (net of cash acquired). The acquisition has been accounted for as a business combination using the purchase method of accounting. The fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:		
Cash paid (net of cash acquired)	$	40,314
Costs associated with acquisition		600
Total purchase price	**$**	**40,914**
Allocation of purchase price:		
Working capital	$	286
Property, plant and equipment		50,540
Asset retirement obligations		(1,371)
Future income tax liability		(8,541)
Total net assets acquired	**$**	**40,914**

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31	
	2010	2009
Petroleum and natural gas properties	**$ 4,229,713**	$ 3,943,850
Accumulated depletion and depreciation	**(2,546,063)**	(2,280,098)
	$ 1,683,650	$ 1,663,752

In calculating the Canadian cost centre depletion and depreciation provision for 2010, $49.6 million (year ended December 31, 2009 – $47.7 million) of costs relating to undeveloped properties were excluded, while $643.1 million (year ended December 31, 2009 – $538.3 million) of future development costs were included in the calculation. In calculating the U.S. cost centre depletion and depreciation provision for 2010, $50.8 million (year ended December 31, 2009 – $77.0 million) of costs relating to undeveloped properties were excluded, while $136.8 million (year ended December 31, 2009 – $77.3 million) of future development costs were included for the calculation. No general and administrative expenses are capitalized.

Depletion and depreciation expense related to the Canadian and U.S. cost centres in 2010 were $258.2 million and $8.3 million respectively (year ended December 31, 2009 – $228.8 million and $4.2 million).

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2010 using the following benchmark reference prices for the years 2011 to 2015 adjusted for commodity differentials specific to the Company:

	2011	2012	2013	2014	2015
WTI crude oil (US$/bbl)	88.40	89.14	88.77	88.88	90.22
AECO natural gas ($/mmBtu)	4.04	4.66	4.99	6.58	6.69
Exchange rate (USD/CAD)	0.932	0.932	0.932	0.932	0.932

The prices and costs subsequent to 2015 have been adjusted for estimated inflation at an estimated annual rate of 1.5 percent. Based on the ceiling test calculations, the Company's estimated undiscounted future net cash flows associated with proved reserves plus the cost less impairment of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN

	As at December 31	
	2010	2009
Bank loan	$ 303,773	$ 265,088

Baytex Energy has established credit facilities with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. In June 2010, Baytex Energy reached agreement with its lending syndicate to amend the revolving credit facilities to increase the amount of the facilities to $550 million (from $515 million), extend the revolving period to June 2011 and add a one-year term-out following the revolving period. In the event that the revolving period is not extended by June 2011, all amounts then outstanding under the credit facilities will be payable in June 2012. 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 or LIBOR rates, plus applicable margins. The credit facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex Energy's assets. The weighted average interest rate on the bank loan for the year ended December 31, 2010 was 4.60% (December 31, 2009 – 4.42%).

7. LONG-TERM DEBT

	As at December 31	
	2010	2009
9.15% Series A senior unsecured debentures	$ 150,000	$ 150,000

On August 26, 2009, Baytex issued $150.0 million principal amount of Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. These debentures are subordinate to Baytex Energy's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525%, and 2015 at 100%.

On September 25, 2009, Baytex Energy redeemed all of the 9.625% senior subordinated notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% senior subordinated notes due February 15, 2011 (principal amount US$0.2 million) for an aggregate redemption price of $196.4 million. These notes were unsecured and were subordinate to Baytex Energy's bank credit facilities. These notes were carried at amortized cost, net of a discontinued fair value hedge. The notes accreted up to the principal balance at maturity using the effective interest method. Baytex Energy recorded accretion expense of $2.8 million for the year ended December 31, 2009. The effective interest rate applied was 10.6%. The discontinued fair value hedge was recognized in interest expense upon redemption of the senior subordinated notes.

8. CONVERTIBLE DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2008	10,398	$ 10,195	$ 498
Conversion	(2,583)	(2,544)	(124)
Accretion	–	85	–
Balance, December 31, 2009	7,815	$ 7,736	$ 374
Conversion	(7,474)	(7,426)	(358)
Accretion	–	31	–
Repayment on maturity	(341)	(341)	(16)
Balance, December 31, 2010	–	$ –	$ –

In June 2005, Baytex issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures paid interest semi-annually and were convertible at the option of the holder at any time into fully-paid trust units at a conversion price of $14.75 per trust unit. On the December 31, 2010 maturity date, the outstanding $0.3 million principal amount was repaid at par value.

The debentures were classified as debt net of the fair value of the conversion feature which was classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion accreted up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid were expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity was reclassified to unitholders' capital along with the principal amount converted.

9. ASSET RETIREMENT OBLIGATIONS

	As at December 31	
	2010	2009
Balance, beginning of year	$ 54,593	$ 49,351
Liabilities incurred	769	1,320
Liabilities settled	(2,778)	(1,146)
Acquisition of liabilities	1,371	3,268
Disposition of liabilities	(840)	(146)
Accretion	4,515	4,184
Change in estimate(1)	(5,249)	(2,212)
Foreign exchange	(8)	(26)
Balance, end of year	$ 52,373	$ 54,593

(1) Changes in the status of wells and changes in the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The future amount of estimated cash flow required to settle the retirement obligations at an estimated annual inflation rate of 2.0% is $288.8 million. The amount of estimated cash flow required to settle the retirement obligations at December 31, 2010, discounted at a credit-adjusted risk free rate of 8.0% is $52.4 million.

10. SHAREHOLDERS'/UNITHOLDERS' CAPITAL

Unitholders' Capital

	Number of Units	Amount
Balance, December 31, 2008	97,685	$ 1,129,909
Issued for cash	7,935	115,058
Issuance costs, net of income tax	–	(5,072)
Issued on conversion of debentures	175	2,667
Issued on exercise of unit rights	2,059	20,523
Transfer from contributed surplus on exercise of unit rights	–	7,306
Issued pursuant to distribution reinvestment plan	1,445	25,540
Balance, December 31, 2009	109,299	$ 1,295,931
Issued on conversion of debentures	507	7,784
Issued on exercise of unit rights	2,337	26,021
Transfer from contributed surplus on exercise of unit rights	–	8,600
Issued pursuant to distribution reinvestment plan	1,569	51,698
Exchanged for common shares, pursuant to the Arrangement	(113,712)	(1,390,034)
Balance, December 31, 2010	**–**	**$ –**

Baytex is authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. Baytex establishes the rights and terms of preferred shares upon issuance. As at December 31, 2010, no preferred shares have been issued by the Company.

Shareholders' Capital

	Number of Common Shares	Amount
Balance, December 31, 2009	–	$ –
Issued pursuant to the Arrangement	113,712	1,390,034
Balance, December 31, 2010	113,712	$ 1,390,034

11. EQUITY BASED INCENTIVE PLANS

Long Term Incentive Plan

The Trust had a Trust Unit Rights Incentive Plan (the "Unit Rights Plan") pursuant to which rights to acquire trust units ("unit rights") were granted to eligible directors, officers, employees and other service providers of the Trust and its subsidiaries. The maximum number of trust units issuable pursuant to the Unit Rights Plan was a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which were issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units resulted in an increase in the number of trust units available for issuance under the Unit Rights Plan, and any exercises of unit rights made new grants available under the Unit Rights Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Unit Rights Plan. Under the Unit Rights Plan, unit rights have a maximum term of five years and vest and become exercisable as to one-third on each of the first, second and third anniversaries of the grant date.

The Unit Rights Plan provided that the exercise price of the unit rights may be reduced to account for future distributions, subject to certain performance criteria. Effective November 16, 2009, the Unit Rights Plan was amended to (i) base the exercise price of unit rights on the closing price of the trust units on the trading day prior to the date of grant (previously based on a five-day volume weighted average trading price) and (ii) permit the granting of unit rights with a fixed exercise price. Effective October 25, 2010, the Unit Rights Plan was amended to provide holders of unit rights who are not subject to taxation in the United States with the ability to elect at the time of exercise to pay an exercise price per unit right equal to (i) the original exercise price reduced for distributions and dividends paid subsequent to grant date or (ii) the original exercise price.

Baytex recorded compensation expense of $8.3 million for the year ended December 31, 2010 (year ended December 31, 2009 – $6.4 million) related to the unit rights granted under the Unit Rights Plan.

Pursuant to the terms of the Unit Rights Plan, the Arrangement (as described in note 1) constituted a capital reorganization which resulted in each holder of unit rights exchanging such rights for equivalent rights to acquire common shares of Baytex ("share rights") on a one-for-one basis on December 31, 2010. The share rights are subject to the terms of the Common Share Rights Incentive Plan of Baytex (the "Share Rights Plan"). The Share Rights Plan is substantially similar to the Unit Rights Plan other than amendments necessary to reflect:

(a) the entitlement of holders to receive common shares instead of trust units;

(b) the exercise price, as calculated for unit rights outstanding at the effective time of the Arrangement, will be carried forward under the Share Rights Plan and, if applicable, future adjustments to the exercise price after the completion of the Arrangement will be based on dividends paid on the common shares of Baytex rather than distributions paid on the trust units of the Trust; and

(c) the administration of the Share Rights Plan will be carried out by Baytex as opposed to Baytex Energy.

As a result of the adoption of the Share Award Incentive Plan (as described below), no further grants will be made under the Share Rights Plan.

Baytex uses the binomial-lattice model to calculate the estimated weighted average fair value of $9.00 per unit right for unit rights issued during the year ended December 31, 2010 (year ended December 31, 2009 – $6.38 per unit right). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2010	2009
Expected annual exercise price reduction (on unit rights with a declining exercise price)	**$2.16 - $2.40**	$1.44 - $2.16
Expected volatility	**43% - 44%**	39% - 43%
Risk-free interest rate	**1.99% - 3.02%**	1.78% - 2.72%
Expected life of unit rights (years)[1]	**Various**	Various

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected lives of share rights or unit rights. The maximum term is limited to five years by the Share Rights Plan.

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

	Number of unit rights	Weighted average exercise price[1]
Balance, December 31, 2008	8,449	$ 14.58
Granted[2]	1,844	24.87
Exercised	(2,059)	9.97
Forfeited	(114)	16.43
Balance, December 31, 2009	8,120	$ 16.68
Granted[2]	190	32.71
Exercised	(2,337)	11.13
Forfeited	(212)	20.35
Exchanged for share rights pursuant to the Arrangement	(5,761)	17.02
Balance, December 31, 2010	**–**	**$ –**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price.
(2) Weighted average exercise price of rights granted is based on the exercise price at the date of grant.

The number of share rights outstanding and exercise prices are detailed below:

	Number of share rights	Weighted average exercise price[1]
Balance, December 31, 2009	–	$ –
Issued pursuant to the Arrangement	5,761	17.02
Balance, December 31, 2010	**5,761**	**$ 17.02**

(1) Weighted average exercise price reflects the exercise price at date of exchange.

The following table summarizes information about the share rights outstanding at December 31, 2010:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Distributions Subsequent to Grant Date				
Price Range	**Number Outstanding at December 31, 2010**	Weighted Average Grant Price	Weighted Average Remaining Term (years)	**Number Exercisable at December 31, 2010**	Weighted Average Exercise Price	**Number Outstanding at December 31, 2010**	Weighted Average Exercise Price	Weighted Average Remaining Term (years)	**Number Exercisable at December 31, 2010**	Weighted Average Exercise Price
$ 6.88 to $13.00	**10**	$ 12.46	3.2	**–**	$ –	**1,395**	$ 12.60	1.9	**1,228**	$ 12.70
$13.01 to $20.00	**3,093**	18.40	2.5	**2,188**	18.79	**2,802**	14.23	2.2	**1,994**	14.04
$20.01 to $27.00	**1,283**	22.50	1.4	**1,090**	22.29	**1,206**	24.84	3.9	**398**	24.84
$27.01 to $34.00	**1,318**	28.04	3.9	**398**	27.75	**305**	28.45	4.0	**56**	27.77
$34.01 to $41.00	**54**	36.97	4.7	**–**	–	**50**	36.80	4.7	**–**	–
$41.01 to $47.72	**3**	44.96	5.0	**–**	–	**3**	44.83	5.0	**–**	–
$ 6.88 to $47.72	**5,761**	$ 21.69	2.6	**3,676**	$ 20.79	**5,761**	$ 17.02	2.6	**3,676**	$ 14.97

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2008	$ 21,234
Compensation expense	6,443
Transfer from contributed surplus on exercise of unit rights(1)	(7,306)
Balance, December 31, 2009	$ 20,371
Compensation expense	8,344
Transfer from contributed surplus on exercise of unit rights(1)	(8,600)
Convertible debentures matured	16
Balance, December 31, 2010	**$ 20,131**

(1) Upon exercise of unit rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

Share Award Incentive Plan

In connection with the Arrangement, the unitholders of the Trust approved, at a special meeting held on December 9, 2010, the adoption by the Company effective January 1, 2011 of a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "Share Awards") may be granted to the directors, officers, employees and other service providers of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plan of the Company, including the Share Rights Plan) shall not at any time exceed 10% of the then issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents as described below) with such common shares to be issued as to one-third on each of the first, second and third anniversary dates of the date of grant. Each performance award entitles the holder to be issued as to one-third on each of the first, second and third anniversary dates of the date of grant the number of common shares designated in the performance award (plus dividend equivalents as described below) multiplied by a payout multiplier. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period and can be one of 0x (for fourth quartile ranking), 1x (for third quartile ranking), 1.5x (for second quartile ranking) and 2x (for first quartile ranking). In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payment of dividends from the grant date to the applicable issue date.

On January 11, 2011, the Compensation Committee of the Board of Directors approved the initial awards under the Share Award Incentive Plan. An aggregate of 228,853 performance awards and 360,847 restricted awards, with 50% to be granted effective January 18, 2011 and the remaining 50% to be granted in July 2011, were awarded to eligible directors, officers, employees and other service providers of the Company and its subsidiaries. The July 2011 grants are conditional on the grantee continuing to be a service provider to the Company or its subsidiaries.

The Company recorded no compensation expense for the year ended December 31, 2010 related to the Share Awards as none were granted during the year ended December 31, 2010.

12. ACCUMULATED OTHER COMPREHENSIVE LOSS

	As at December 31	
	2010	2009
Balance, beginning of year	**$ (3,899)**	$ –
Foreign currency translation adjustment	**(10,708)**	(3,899)
Balance, end of year	**$ (14,607)**	$ (3,899)

Accumulated other comprehensive loss is composed entirely of currency translation adjustments on the translation of self-sustaining foreign operations. The Company's foreign operations are considered to be "self-sustaining operations", as they are financially and operationally independent of the Canadian operations. As a result, the accounts of the self-sustaining foreign operations are translated using the current rate method whereby assets and liabilities are translated using the exchange rate in effect at the balance sheet date, while revenues and expenses are translated using the average exchange rate for the year ended December 31, 2010. Translation gains and losses are deferred and included in accumulated other comprehensive loss in shareholders' equity and are recognized in net income when there has been a reduction in the net investment.

13. NET INCOME PER COMMON SHARE AND PER TRUST UNIT

Baytex applies the treasury stock method to assess the dilutive effect of outstanding share rights or unit rights on net income per common share or trust unit. The trust units issuable on conversion of convertible debentures were included in the calculation of the diluted weighted average number of common shares or trust units outstanding:

	Years Ended December 31					
	2010			2009		
	Net income	Common shares	Net income per common share	Net income	Trust units	Net income per trust unit
Net income per common share or trust unit – basic	$ 177,631	111,450	$ 1.59	$ 87,574	104,894	$ 0.83
Dilutive effect of share rights or unit rights	–	3,673		–	1,697	
Conversion of convertible debentures	297	397		502	655	
Net income per common share or trust unit – diluted	$ 177,928	115,520	$ 1.54	$ 88,076	107,246	$ 0.82

For the year ended December 31, 2010, 0.1 million share rights (year ended December 31, 2009 – 1.6 million unit rights) were excluded in calculating the weighted average number of diluted common shares or trust units outstanding as they were anti-dilutive.

14. INCOME TAXES

The provision for (recovery of) income taxes has been computed as follows:

	Years Ended December 31	
	2010	2009
Income before income taxes	$ 154,083	$ 68,487
Expected income tax expense at the statutory rate of 28.49% (2009 – 29.48%)	43,898	20,190
Increase (decrease) in income taxes resulting from:		
Net income of the Trust prior to the Arrangement	(69,342)	(50,474)
Non-taxable portion of foreign exchange gain	(1,333)	(2,994)
Effect of change in income tax rate	(1,285)	601
Effect of change in opening tax pool balances	(6,373)	5,501
Effect of change in valuation allowance	–	(5,374)
Unit-based compensation	2,377	1,899
Other	(2)	194
Future income tax recovery	(32,060)	(30,457)
Current income tax expense	8,512	11,370
Income tax recovery	$ (23,548)	$ (19,087)

The components of the net future income tax liability are as follows:

	As at December 31	
	2010	2009
Future income tax liabilities:		
Petroleum and natural gas properties	$ (205,104)	$ (200,820)
Financial derivative contracts	(707)	(749)
Partnership deferral	(52,804)	–
Other	(2,920)	(5,438)
Future income tax assets:		
Asset retirement obligations	13,480	13,929
Non-capital losses	225,888	13,185
Financial derivative contracts	2,390	418
Finance costs	2,665	220
Net future income tax liability-long-term(1)	$ (17,112)	$ (179,255)
Current portion of future income tax liability(2)	(3,756)	(8,683)
Current portion of future income tax asset(2)	5,480	1,371
Net future income tax liability-current	$ 1,724	$ (7,312)
Net future income tax liability-total	$ (15,388)	$ (186,567)

(1) Non-capital loss carry-forwards totaled $822.9 million (December 31, 2009 – $48.4 million) and expire from 2014 to 2030.
(2) The current portion of future income tax asset and liability are derived from the current portion of financial derivative contracts.

In May 2010, Baytex acquired a number of private entities for use in its internal financing structure for approximately $38.0 million. The transaction resulted in the recognition of a future income tax asset of approximately $147.8 million with a corresponding deferred credit of $109.8 million. This credit reflects the difference between the future tax asset recognized upon the completion of this transaction and the cash paid. This credit will be amortized on the same basis as the related future income tax asset.

15. INTEREST EXPENSE

Baytex incurred interest expense on its outstanding debts as follows:

	Years Ended December 31	
	2010	2009
Bank loan and other	$ 12,530	$ 9,394
Long-term debt	13,725	22,578
Convertible debentures	415	713
Interest expense	$ 26,670	$ 32,685

16. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2010	2009
Current assets	$ (13,336)	$ (50,655)
Current liabilities	(2,661)	16,140
Foreign exchange	74	50
	$ (15,923)	$ (34,465)
Changes in non-cash working capital related to:		
Operating activities	$ (9,967)	$ (27,878)
Investing activities	(5,956)	(6,587)
	$ (15,923)	$ (34,465)

Supplemental Cash Flow Information

Baytex made the following cash outlays in respect of interest, financing charges and current income taxes paid:

	Years Ended December 31	
	2010	2009
Interest paid	$ 26,826	$ 33,002
Financing charges paid	$ 1,674	$ 5,278
Current income taxes paid	$ 8,439	$ 10,534

Foreign Exchange Gain

	Years Ended December 31	
	2010	2009
Unrealized foreign exchange gain	$ (8,999)	$ (2,623)
Realized foreign exchange gain(1)	(149)	(20,201)
Foreign exchange gain	$ (9,148)	$ (22,824)

(1) The retirement of the US$ senior subordinated notes on September 25, 2009 resulted in a realized gain of $51.0 million. Only $23.7 million of this gain is recognized in the twelve months ended December 31, 2009 as $27.3 million was reported in prior periods as an unrealized foreign exchange gain through the translation process at each period end.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, convertible debentures, financial derivative contracts and long-term debt.

Classification of Financial Instruments

Under GAAP, financial instruments are classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale and other financial liabilities.

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan, convertible debentures and long-term debt, are equal to their book amounts due to the short-term maturity of these instruments. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows plus the conversion option associated with the convertible debentures. The fair value of the long-term debt is based on the lower of trading value and the present value of future cash flows associated with the debentures. Baytex expenses all financial instrument transaction costs immediately.

Baytex classifies the fair value of the financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The carrying value and fair value of the Company's financial instruments on the consolidated balance sheets are classified into the following categories:

	December 31, 2010		December 31, 2009		
	Carrying Value	Fair Value	Carrying Value	Fair Value	Fair Value Measurement Hierarchy
Financial Assets					
Held-for-trading					
Cash	$ –	$ –	$ 10,177	$ 10,177	Level 1
Derivatives designated as held-for-trading	16,543	16,543	31,994	31,994	Level 2
Total held-for-trading	$ 16,543	$ 16,543	$ 42,171	$ 42,171	
Loans and receivables					
Accounts receivable	$ 151,792	$ 151,792	$ 137,154	$ 137,154	–
Total loans and receivables	$ 151,792	$ 151,792	$ 137,154	$ 137,154	
Financial Liabilities					
Held-for-trading					
Derivatives designated as held-for-trading	$ (29,171)	$ (29,171)	$ (6,068)	$ (6,068)	Level 2
Total held-for-trading	$ (29,171)	$ (29,171)	$ (6,068)	$ (6,068)	
Other financial liabilities					
Accounts payable and accrued liabilities	$ (179,269)	$ (179,269)	$ (180,493)	$ (180,493)	–
Distributions payable to unitholders	(22,742)	(22,742)	(19,674)	(19,674)	–
Bank loan	(303,773)	(303,773)	(265,088)	(265,088)	–
Convertible debentures	–	–	(7,736)	(15,474)	Level 1
Long-term debt	(150,000)	(163,875)	(150,000)	(162,750)	Level 1
Total other financial liabilities	$ (655,784)	$ (669,659)	$ (622,991)	$ (643,479)	

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk

Baytex is exposed to fluctuations in foreign currency as a result of the U.S. dollar portion of its bank loan, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Company's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of currency exchange rate fluctuations, the Company may enter into agreements to fix the Canada – United States exchange rate.

At December 31, 2010, Baytex had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price[1]
Forward sales	January 1, 2010 to March 31, 2011	US$5.0 million	1.1500
Forward sales	January 1, 2010 to December 31, 2011	US$5.0 million	1.0711
Forward sales	April 1, 2010 to March 31, 2011	US$1.0 million	1.0185
Forward sales	June 1, 2010 to June 30, 2012	US$1.0 million	1.0250
Forward sales	January 1, 2011 to December 31, 2011	US$3.0 million	1.0677
Forward sales	January 1, 2011 to June 30, 2012	US$3.0 million	1.0622
Forward sales	January 1, 2011 to August 31, 2012	US$1.0 million	1.0565
Forward sales	January 1, 2011 to September 30, 2012	US$1.5 million	1.0553
Forward sales	November 1, 2011 to October 31, 2013	US$1.0 million	1.0433

(1) Based on the weighted average exchange rate (CAD/USD).

The following table demonstrates the effect of movements in the Canada – United States exchange rate on net income before income taxes due to changes in the fair value of the currency swaps, as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2010.

	$0.01 Increase (Decrease) in CAD/USD Exchange Rate
Loss (gain) on currency forward sales agreements	$ 2,469
Loss (gain) on other monetary assets/liabilities	1,741
Impact on income before income taxes and comprehensive income	$ 4,210

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
U.S. dollar denominated	**US$ 72,663**	US$ 67,389	**US$ 230,723**	US$ 198,690

Interest rate risk

The Company's interest rate risk arises from its floating rate bank credit facilities. As at December 31, 2010, $303.8 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income before taxes for the year ended December 31, 2010 by approximately $3.1 million. Baytex uses a combination of short-term and long-term debt to finance its operations. The bank loan is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

At December 31, 2010, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay floating, receive fixed	September 23, 2009 to August 26, 2011	Cdn$150.0 million	9.15%	3-month BA plus 7.875%
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	September 25, 2012 to September 25, 2014	US$90.0 million	4.39%	3-month LIBOR

When assessing the potential impact of forward interest rate changes on financial derivative contracts outstanding as at December 31, 2010, an increase or decrease of 100 basis points would result in an increase or decrease, respectively, to the unrealized loss in year ended December 31, 2010 by approximately $3.7 million.

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Baytex. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2010, a 10% increase would increase the unrealized loss at December 31, 2010 by $36.4 million, while a 10% decrease would decrease the unrealized loss at December 31, 2010 by $35.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2010, a 10% increase would increase the unrealized loss at December 31, 2010 by $1.9 million, while a 10% decrease would decrease the unrealized loss at December 31, 2010 by $2.0 million.

Financial Derivative Contracts

At December 31, 2010, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Time spread	January 2011	2,000 bbl/d	Dec 2011 less US$3.20	WTI
Fixed – Sell	January to June 2011	500 bbl/d	US$91.69	WTI
Price collar	July to December 2011	500 bbl/d	US$90.00 - 95.00	WTI
Price collar	Calendar 2011	1,000 bbl/d	US$90.00 - 98.00	WTI
Fixed – Sell	Calendar 2011	1,500 bbl/d	US$86.60	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	US$85.79	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	US$87.15	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$86.60	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$85.40	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$85.40	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$90.05	WTI
Fixed – Sell	Calendar 2011	500 bbl/d	US$90.75	WTI
Price collar	Calendar 2011	500 bbl/d	US$85.00 - 90.00	WTI
Price collar	Calendar 2011	500 bbl/d	US$85.00 - 92.50	WTI
Price collar	Calendar 2011	500 bbl/d	US$87.50 - 92.00	WTI
Price collar	Calendar 2011	500 bbl/d	US$89.00 - 92.20	WTI
Price collar	Calendar 2011	500 bbl/d	US$89.00 - 92.30	WTI
Fixed – Sell	Calendar 2011	1,000 bbl/d	WTI × 82.00%	WCS

Natural Gas	Period	Volume	Price/Unit	Index
Sold call	March 2011	3,000 mmBtu/d	US$6.25	NYMEX
Sold call	July to December 2011	3,000 mmBtu/d	US$6.25	NYMEX
Sold call	July to December 2011	3,000 mmBtu/d	US$5.00	NYMEX
Fixed – Sell	July to December 2011	2,500 mmBtu/d	US$4.50	NYMEX
Fixed – Sell	July to December 2011	2,500 mmBtu/d	US$4.62	NYMEX
Basis swap	Calendar 2011	4,000 mmBtu/d	NYMEX less US$0.615	AECO
Basis swap	Calendar 2011	2,000 mmBtu/d	NYMEX less US$0.490	AECO
Sold call	Calendar 2012	6,000 mmBtu/d	US$5.25	NYMEX

Financial derivative contracts are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income and comprehensive income:

	Years Ended December 31	
	2010	2009
Realized gain on financial derivative contracts	$ 48,129	$ 80,818
Unrealized loss on financial derivative contracts	(38,194)	(54,810)
Gain on financial derivative contracts	$ 9,935	$ 26,008

Subsequent to December 31, 2010, Baytex added the following financial derivative contracts:

Oil	Period	Volume	Price/Unit	Index
Fixed – Sell	March to December 2011	500 bbl/d	US$95.10	WTI
Fixed – Sell	March to December 2011	500 bbl/d	US$96.24	WTI
Fixed – Sell	March to December 2011	500 bbl/d	US$100.76	WTI
Fixed – Sell	March to December 2011	250 bbl/d	US$102.28	WTI
Fixed – Sell	March to December 2011	250 bbl/d	US$104.40	WTI
Price collar	March to December 2011	250 bbl/d	US$95.00 - 107.20	WTI
Price collar	March to December 2011	200 bbl/d	US$100.00 - 112.60	WTI
Time spread	March to December 2011	500 bbl/d	Dec 2013 plus US$1.40	WTI
Time spread	July 2011	2,500 bbl/d	Dec 2013 less US$2.75	WTI
Time spread	August 2011	2,500 bbl/d	Dec 2013 less US$2.31	WTI
Price collar	Calendar 2011	200 bbl/d	US$91.50 - 94.85	WTI
Price collar	Calendar 2011	200 bbl/d	US$92.50 - 96.65	WTI
Price collar	Calendar 2011	300 bbl/d	US$91.00 - 97.60	WTI
Fixed – Sell	Calendar 2011	200 bbl/d	US$93.20	WTI
Fixed – Sell	Calendar 2011	200 bbl/d	US$94.30	WTI
Fixed – Sell	Calendar 2011	300 bbl/d	US$94.45	WTI
Fixed – Sell	February 2011 to December 2012	500 bbl/d	US$98.33	WTI

Natural Gas	Period	Volume	Price/Unit	Index
Fixed – Sell	March to June 2011	3,000 mmBtu/d	US$4.71	NYMEX
Fixed – Sell	July to December 2011	1,000 mmBtu/d	US$4.90	NYMEX

Physical Delivery Contracts

At December 31, 2010, the following physical delivery contracts were entered into and continue to be held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts do not meet the definition of a financial instrument; therefore, no asset or liability has been recognized in the financial statements.

Heavy Oil	Period	Volume	Weighted Average Price/Unit
LLK Blend	June to August 2011	2,000 bbl/d	WTI less US$14.75
WCS Blend	June to August 2011	500 bbl/d	WTI less US$15.50
WCS Blend	April to June 2011	2,000 bbl/d	WTI less US$15.80
WCS Blend	April to June 2011	1,000 bbl/d	WTI less US$16.00
WCS Blend	July to September 2011	2,000 bbl/d	WTI less US$15.60
WCS Blend	July to September 2011	1,000 bbl/d	WTI less US$16.00
LLB Blend	January to March 2011	2,000 bbl/d	WTI less US$15.00
LLB Blend	January to September 2011	1,000 bbl/d	WTI less US$15.25
WCS Blend	Calendar 2011	2,000 bbl/d	WTI less US$15.38
WCS Blend	Calendar 2011	1,000 bbl/d	WTI × 82.00%
WCS Blend	Calendar 2011	1,000 bbl/d	WTI × 82.90%
WCS Blend	Calendar 2011	1,000 bbl/d	WTI less US$16.00
WCS Blend	Calendar 2011	500 bbl/d	WTI less US$15.00
WCS Blend	Calendar 2012	2,000 bbl/d	WTI less US$16.50
WCS Blend	January to June 2013	3,000 bbl/d	WTI less US$17.00

Natural Gas	Period	Volume	Price/Unit
Fixed – Sell	February to November 2011	2,500 GJ/d	AECO Cdn$5.03
Price collar	Calendar 2011	2,500 GJ/d	AECO Cdn$5.50 - 7.10
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.80
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.71
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.82
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$4.88
Fixed – Sell	Calendar 2011	1,000 GJ/d	AECO Cdn$5.00

Subsequent to December 31, 2010, Baytex added the following physical delivery contracts:

Heavy Oil	Period	Volume	Price/Unit
WCS Blend	April to December 2011	2,000 bbl/d	WTI × 80.25%
WCS Blend	June to August 2011	1,000 bbl/d	WTI less US$17.00

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional common shares. As at December 31, 2010, Baytex had available unused bank credit facilities in the amount of $246.2 million.

The timing of cash outflows (excluding interest) relating to financial liabilities is outlined in the table below:

	Total	Less than 1 year	1-2 years	3-5 years	Beyond 5 years
Accounts payable and accrued liabilities	$ 179,269	$ 179,269	$ –	$ –	$ –
Distributions payable to unitholders	22,742	22,742	–	–	–
Bank loan[(1)]	303,773	–	303,773	–	–
Long-term debt[(2)]	150,000	–	–	–	150,000
	$ 655,784	$ 202,011	$ 303,773	$ –	$ 150,000

(1) The bank loan is a 364-day revolving loan with a one year term-out following the 364-day revolving period with the ability to extend the term. Unless extended, the revolving period will end on June 27, 2011 with all amounts to be re-paid by June 27, 2012.

(2) Principal amount of instrument.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. Most of the Company's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. Baytex manages this credit risk by entering into sales contracts with only creditworthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative contracts. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

Should Baytex determine that the ultimate collection of a receivable is in doubt based on the processes for managing credit risk, the carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income. If the Company subsequently determines that an account is uncollectible, the account is written-off with a corresponding change to allowance for doubtful accounts. For the year ended December 31, 2010, $0.4 million was written-off in relation to balances already provided for in 2009 (year ended December 31, 2009 – $0.1 million write-off). As at December 31, 2010, a balance of $1.9 million (December 31, 2009 – $2.3 million) has been set up as allowance for doubtful accounts.

As at December 31, 2010, accounts receivable included a $4.8 million balance over 90 days (December 31, 2009 – $8.5 million) and considered past due.

18. COMMITMENTS AND CONTINGENCIES

At December 31, 2010, Baytex had the following obligations under operating leases and processing and transportation agreements:

	Total	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Beyond 5 years
Operating leases	$ 55,645	$ 5,667	$ 5,687	$ 5,748	$ 6,066	$ 6,218	$ 26,259
Processing and transportation agreements	4,207	3,175	899	107	26	–	–
Total	$ 59,852	$ 8,842	$ 6,586	$ 5,855	$ 6,092	$ 6,218	$ 26,259

At December 31, 2010, the following physical power contracts were entered into and continue to be held for the purpose of delivery of non-financial items in accordance with the Company's expected usage requirements. Physical power contracts do not meet the definition of a financial instrument; therefore, no asset or liability has been recognized in the financial statements.

Power	Period	Volume	Price/Unit
Fixed – Buy	July 2010 to December 2011	0.2 MW	Cdn$49.11/MWh
Fixed – Buy	January to December 2011	0.2 MW	Cdn$47.71/MWh
Fixed – Buy	January to December 2011	0.2 MW	Cdn$46.75/MWh
Fixed – Buy	January to December 2011	0.3 MW	Cdn$45.46/MWh

Other

During 2009, Baytex implemented an Income Tracking Unit Plan. Liabilities incurred under this plan are settled in cash on predetermined dates, contingent upon attainment of prescribed payment conditions, including the participant's service status with Baytex and the intrinsic value of reference share rights. Liabilities are recorded when the likelihood of the prescribed payment conditions being met can be reasonably estimated. At December 31, 2010, a liability of $0.4 million has been accrued (December 31, 2009 – $0.1 million).

At December 31, 2010 and December 31, 2009, there were no outstanding letters of credit.

In connection with a purchase of properties in 2005, Baytex Energy became liable for contingent consideration whereby an additional amount would be payable by Baytex Energy if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase; therefore, such consideration is recognized only when the contingency is resolved. As at December 31, 2010, additional payments totaling $9.6 million have been paid under the agreement and recorded as an adjustment to the original purchase price of the properties. It is currently not determinable, what amount, if any, of further payments will be required for the remaining year under this agreement; therefore, no accrual has been made.

Baytex is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Company's financial position or reported results of operations.

19. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

Baytex considers its capital structure to include total monetary debt and shareholders' equity. Total monetary debt is a non-GAAP measure which is the sum of monetary working capital (being current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative contracts gains or losses)), and the principal amount of long-term debt and long-term bank loan. At December 31, 2010, total monetary debt was $502.2 million.

The Company's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, Baytex may adjust the amount of its dividends, adjust its level of capital spending, issue new common shares or debt, or sell assets to reduce debt.

Baytex monitors capital based on the current and projected ratio of total monetary debt to funds from operations and the current and projected level of its undrawn bank credit facilities. Funds from operations is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. The Company's objectives are to maintain a total monetary debt to funds from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to funds from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to funds from operations ratio and the level of undrawn bank credit facilities, Baytex continuously monitors its funds from operations and evaluates its dividend policy and capital spending plans.

Although Baytex has changed its legal form to a corporation, its financial objectives and strategy over the last two completed fiscal years as described above have remained substantially unchanged. These objectives and strategy are reviewed on an annual basis and Baytex believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

Baytex is subject to financial covenants relating to its senior unsecured debentures and the credit facilities of Baytex Energy. Baytex is in compliance with all financial covenants.

20. SUBSEQUENT EVENTS

An agreement was reached on January 1, 2011 between Baytex Energy and its lending syndicate to increase the amount of the credit facilities to $625 million (from $550 million), to decrease its margins on advances based on the prime lending rate, bankers' acceptance rates or LIBOR rates and to decrease standby fees. The credit facilities were further increased to $650 million (from $625 million) effective February 17, 2011.

On February 3, 2011, Baytex Energy completed the acquisition of heavy oil assets located in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan. The assets were acquired through a combination of a corporate acquisition of a private company and an asset acquisition. The total consideration for the acquisitions of $159.4 million (net of adjustments) was funded by drawing on Baytex Energy's revolving credit facilities.

On February 17, 2011, Baytex Energy issued US$150 million in 10 year senior unsecured debentures at par bearing a coupon rate of 6.75%, and used the net proceeds from this issue to repay a portion of the amount drawn in Canadian currency on its credit facilities.

21. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

This information should be read in conjunction with the audited consolidated financial statements of Baytex Energy Corp. ("Baytex" or the "Company") as at and for the periods ended December 31, 2010 and 2009. The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), which in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are as described below:

Reconciliation of Net Income under Canadian GAAP to U.S. GAAP

	Note	Years ended December 31 2010	2009
Net income – Canadian GAAP		$ 177,631	$ 87,574
Increase (decrease) under U.S. GAAP:			
Depletion, depreciation and accretion	A,B	66,870	72,721
Interest, net	C	31	3,174
Financing charges		–	3,631
General and administrative	K	(600)	–
Unit-based compensation	G	(74,690)	(92,627)
Income tax expense	H	(24,488)	(34,541)
Net income – U.S. GAAP		$ 144,754	$ 39,932
Net income per common share or trust unit			
Basic		$ 1.30	$ 0.38
Diluted		$ 1.27	$ 0.38
Weighted average common shares or trust units			
Basic		111,450	104,894
Diluted		114,316	106,419

Condensed Consolidated Statements of Operations – U.S. GAAP

	Note	Years ended December 31 2010	2009
Revenue			
Petroleum and natural gas sales, net of royalties	I	$ 842,804	$ 659,105
Gain on financial derivative contracts		9,935	26,008
		852,739	685,113
Expenses			
Operating	G	180,439	176,706
Transportation and blending		188,591	159,354
General and administrative	G,K	114,709	120,620
Interest	J	26,639	29,511
Financing charges		1,643	1,865
Foreign exchange gain		(9,148)	(22,824)
Depletion, depreciation and accretion	A,B	204,172	164,495
		707,045	629,727
Income before taxes		145,694	55,386
Income tax expense (recovery)			
Current		8,512	11,370
Deferred	H	(7,572)	4,084
		940	15,454
Net income		144,754	39,932
Other comprehensive loss			
Foreign currency translation adjustment		(10,697)	(3,951)
Comprehensive income		$ 134,057	$ 35,981

Consolidated Statements of Accumulated Deficit

	Note	Years ended December 31 2010	2009
Deficit, beginning of the year		$ (2,633,298)	$ (1,206,793)
Net income		144,754	39,932
Distributions to unitholders	F	(243,383)	(164,040)
Adjustment for fair value of temporary equity	E	(1,754,562)	(1,324,447)
Adjustment for fair value of unit rights exercised	G	39,780	22,050
Deficit, end of the year		$ (4,446,709)	$ (2,633,298)

Condensed Consolidated Balance Sheets – U.S. GAAP

		As at December 31			
		2010		2009	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets	M	$ 172,995	$ 172,995	$ 179,539	$ 179,539
Financial derivative contracts		2,622	2,622	2,541	2,541
Petroleum and natural gas properties	A,D,K	4,229,713	4,128,907	3,943,850	3,843,644
Accumulated depletion & depreciation	A	(2,546,063)	(3,201,382)	(2,280,098)	(3,002,832)
Petroleum and natural gas properties, net		1,683,650	927,525	1,663,752	840,812
Deferred charges	B	–	2,932	–	3,501
Future income tax asset	H	150,190	150,190	418	4,756
Goodwill		37,755	37,755	37,755	37,755
		$ 2,047,212	$ 1,294,019	$ 1,884,005	$ 1,068,904
Liabilities and Unitholders' Equity					
Current liabilities	C,M	$ 226,079	$ 226,079	$ 486,324	$ 486,403
Bank loan		303,773	303,773	–	–
Deferred credit		109,800	109,800	–	–
Long-term debt		150,000	150,000	150,000	150,000
Asset retirement obligations		52,373	52,373	54,593	54,593
Share-based payment liability	G	–	–	–	91,430
Future income tax liability	A,D,H	167,302	8,531	179,673	749
Financial derivative contracts		8,859	8,859	1,418	1,418
		1,018,186	859,415	872,008	784,593
Temporary equity	E	–	–	–	2,921,560
Shareholders' capital	E,F	1,390,034	4,770,225	–	–
Unitholders' capital	E,F	–	–	1,295,931	–
Conversion feature of convertible debentures	C	–	–	374	–
Contributed surplus	E,G	20,131	125,758	20,371	–
Accumulated other comprehensive loss		(14,607)	(14,670)	(3,899)	(3,951)
Deficit		(366,532)	(4,446,709)	(300,780)	(2,633,298)
		1,029,026	434,604	1,011,997	(2,637,249)
		$ 2,047,212	$ 1,294,019	$ 1,884,005	$ 1,068,904

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

	Years ended December 31	
	2010	2009
Operating activities:		
Net income	$ 144,754	$ 39,932
Unit-based compensation	83,034	99,070
Depletion, depreciation and accretion	203,619	162,329
Amortization of deferred charges	553	2,166
Unrealized foreign exchange gain	(8,999)	(2,889)
Unrealized loss on financial derivative contracts	38,194	54,810
Deferred income tax (recovery) expense	(7,572)	4,084
Realized foreign exchange gain on redemption of long-term debt	–	(23,685)
Change in non-cash working capital	(9,967)	(27,878)
Asset retirement expenditures	(2,778)	(1,146)
	$ 440,838	$ 306,793
Cash (used in) from financing activities	$ (114,890)	$ 7,210
Cash (used in) investing activities	$ (335,436)	$ (303,758)
Impact of foreign exchange on cash balances	$ (689)	$ (68)

(A) Full Cost Accounting

Under U.S. GAAP, for determining the limitation of capitalized costs, the carrying value of a cost centre's oil and gas properties cannot exceed the present value of after tax future net cash flows from proved reserves, discounted at 10%, using oil and gas prices based upon an average price in the prior 12-month period and unescalated costs, plus (i) the costs of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation, less (iii) income tax effects related to differences between the book and tax basis of the properties. The amount of the impairment expense is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost centre's petroleum and natural gas properties.

For Canadian GAAP, the carrying value includes all capitalized costs for each cost centre, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. The U.S. GAAP definition under Regulation S-X is similar to Canadian GAAP, except that under U.S. GAAP the carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

Petroleum and natural gas properties under U.S. GAAP is summarized the following table:

	As at December 31	
	2010	2009
Net book value		
Canada	$ 791,541	$ 732,906
USA	135,984	107,906
	$ 927,525	$ 840,812

The costs of unproved properties included in the petroleum and natural gas properties on the balance sheet date December 31, 2010, which have been excluded from the depletion and ceiling test calculations, by year in which the costs were incurred are summarized in the following table:

	Total	2010	2009	Prior to 2009
Property acquisitions				
Canada	$ 49,603	$ 17,340	$ 1,797	$ 30,466
USA	50,793	7,832	25,555	17,406
	$ 100,396	$ 25,172	$ 27,352	$ 47,872

The costs of unproved properties are amortized into the depletion base over five years for Canadian cost centre and three years for the U.S. cost centre. There were no major development projects that were excluded from the capitalized costs being amortized.

Under Canadian GAAP, depletion is calculated by reference to proved reserves estimated using forecast prices. Under U.S. GAAP, depletion is calculated by reference to proved reserves estimated using unescalated prices. The difference in proved reserves and the effect of prior years' write-downs under U.S. GAAP have resulted in $86.7 million less depletion recorded under U.S. GAAP for the year ended December 31, 2010 (year ended December 31, 2009 – $81.2 million less depletion).

At December 31, 2010, Baytex's capitalized costs of petroleum and natural gas properties in both the Canadian cost centre and U.S. cost centre did not exceed the full cost ceiling under U.S. GAAP. At June 30, 2010, the ceiling test in the U.S. cost centre resulted in a charge of $19.3 million. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes. At December 31, 2009, Baytex's capitalized costs of petroleum and natural gas properties in the Canadian cost centre did not exceed the full cost ceiling under U.S. GAAP. The ceiling test in the U.S. cost centre resulted in a charge of $6.3 million.

(B) Deferred Charges

Under Canadian GAAP, the Company elected to expense all financial instrument transaction costs immediately. Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial asset or financial liability. Under U.S. GAAP, transaction costs continue to be deferred and amortized over the expected term of the related financial asset or liability. Under U.S. GAAP, there is an asset of $2.9 million on the balance sheet at December 31, 2010 (December 31, 2009 – $3.5 million). For the year ended December 31, 2010 additional amortization expense of $0.6 million has been recognized in net income under U.S. GAAP (year ended December 31, 2009 – $2.2 million).

(C) Convertible Debentures

Under Canadian GAAP, the Company's convertible debentures were classified as debt with a portion, representing the value associated with the conversion feature, being allocated to equity. In addition, under Canadian GAAP a non-cash interest expense representing the effective yield of the debt component was recorded in the consolidated statements of income with a corresponding credit to the convertible debenture liability balance to accrete the balance to the principal due December 31, 2010, on maturity.

Under U.S. GAAP, the convertible debentures in their entirety were classified as debt. The non-cash interest expense recorded under Canadian GAAP would not be recorded under U.S. GAAP. As a result of the December 31, 2010 maturity, no equity was reclassified to liabilities as at December 31, 2010 (December 31, 2009 – $0.4 million) and $31 thousand of non-cash interest expense was reversed (December 31, 2009 – $0.1 million).

(D) Step Acquisition on Exchange of Exchangeable Shares

Under Canadian GAAP, when the exchangeable shares are exchanged for common shares, the transaction is treated as a step acquisition whereby petroleum and natural gas properties are increased by the tax-effected difference between the fair value of the exchangeable shares and their carrying value. The offset is credited to future tax liability and common shares. Under U.S. GAAP the exchangeable shares are considered to be a component of temporary equity and therefore no business combination is considered to have occurred. The cumulative effect of the reversal of the step acquisition is a reduction in petroleum and natural gas properties of $62.0 million (December 31, 2009 – $70.4 million) and a decrease in future tax liability of $17.7 million (December 31, 2009 – $20.8 million).

(E) Temporary Equity

The trust units contained a redemption feature which was required for Baytex to retain its mutual fund trust status for Canadian income tax purposes. The redemption feature of the trust units entitled the holder to redeem the trust units. However, the restrictions on redemption were not substantive enough for the trust units to be accounted for as a component of permanent unitholders' equity under U.S. GAAP. In accordance with Accounting Standards Codification ("ASC") 480 "Distinguishing Liabilities from Equity" (formerly, Emerging Issues Task Force D-98 "Classification and Measurement of Redeemable Securities"), the trust units were presented as temporary equity and recorded on the consolidated balance sheet at their redemption value.

Under Canadian GAAP, all trust units are classified as permanent equity. Changes in redemption value are charged or credited to accumulated deficit. Immediately prior to the conversion from an income trust to a corporation at December 31, 2010, in accordance with U.S. GAAP, the trust had recorded temporary equity in the amount of $4,770.2 million (December 31, 2009 – $2,921.6 million), which represented the estimated redemption value of the trust units at the balance sheet date. Prior to the conversion from an income trust to a corporation, the difference between the Trust's temporary equity under U.S. GAAP and unitholders' capital under Canadian GAAP was applied to accumulated deficit. The adjustments to accumulated deficit was a debit of $1,754.6 million (December 31, 2009 – debit of $1,324.4 million).

On December 31, 2010 the Trust effectively completed its conversion from an income trust to a corporation. Pursuant to the Arrangement, all outstanding trust units were exchanged for common shares of the Company. Under both Canadian and U.S. GAAP, this exchange was recorded at carrying value of the trust units outstanding at December 31, 2010. Due to the classification of Baytex's trust units as temporary equity under U.S. GAAP, recorded at their redemption amount, the carrying value of shareholders' equity varied between U.S. and Canadian GAAP. Prior to the Trust's conversion to a corporation, Baytex had classified $4,770.2 million as temporary equity, in accordance with U.S. GAAP (which was reclassified to shareholders' capital upon conversion).

(F) Shareholders'/Unitholders' Capital

Distributions declared for the year ended December 31, 2010 were $2.18 per trust unit (year ended December 31, 2009 – $1.56 per trust unit). The number of common shares outstanding as at December 31, 2010 was 113,712,158 (December 31, 2009 – 109,298,911 trust units). Under U.S. GAAP, the number of common shares issued and outstanding is required to be disclosed on the face of the balance sheet.

There were no costs relating to the issuance of common shares or trust units netted against shareholders' or unitholders' capital for the year ended December 31, 2010 (year ended December 31, 2009 – $5.1 million).

(G) Unit-Based Compensation

Baytex had a Trust Units Rights Incentive Plan (the "Unit Rights Plan"), which was superseded by the Company's Common Share Rights Incentive Plan (the "Share Rights Plan") upon conversion from an income trust to a corporation as described in note 11. As the exercise price of the unit rights granted under the Unit Rights Plan were subject to downward revisions from time to time, the Unit Rights Plan was a variable compensation plan under U.S. GAAP. Under ASC 718 – "Compensation – Stock Compensation" (formerly, SFAS No. 123R "Share-Based Payments"), the Company must account for compensation expense based on the fair value at report date of unit rights granted under the Unit Rights Plan, and unlike Canadian GAAP, must allocate the compensation expense between grants issued to operations and general and administrative staff respectively. The fair value of the unit rights has been determined using a binomial-lattice model.

The modification of the awards plan from the Unit Rights Plan to the Share Rights Plan resulted in a change from liability awards to equity awards. The Share Rights Plan under ASC 718 would require reclassifying the fair value of share rights as at December 31, 2010 of $125.8 million from share based liability to contributed surplus. No additional compensation expense was recorded for the year ended December 31, 2010 as a result of the modification. The expense recognized from the date of modification over the remainder of the vesting period is determined based on the fair value of the reclassified equity awards as at the date of modification.

Prior to the conversion to a corporation, the Unit Rights Plan was classified as a liability and the unit rights were fair valued at each reporting date. Compensation expense for the Unit Rights Plan was recognized in income until settlement date based on the reporting date fair value and the portion of the vesting period that has transpired. The accounting for compensation expense for the Unit Rights Plan results in a difference between Canadian and U.S. GAAP, as Baytex classifies the Unit Rights Plan as equity awards and uses the grant date fair value method to account for its unit compensation expense under Canadian GAAP. Under U.S. GAAP compensation expense increased by $74.7 million for the year ended December 31, 2010 (December 31, 2009 – increased by $92.6 million) resulting in an expense of $83.0 million (December 31, 2009 – $99.1 million). The allocation between operating and general and administrative expenses under U.S. GAAP for the year ended December 31, 2010 was $8.7 million and $74.3 million respectively (year ended December 31, 2009 – $13.5 million and $85.6 million). Difference in fair value of unit rights under U.S. GAAP resulted in an adjustment to accumulated deficit upon exercise of unit rights for the year ended December 31, 2010 for a credit of $39.8 million (December 31, 2009 – credit of $22.1 million).

The Company used the binomial-lattice model to calculate the estimated weighted average grant date fair value of $9.00 per unit right for unit rights issued during the year ended December 31, 2010 (year ended December 31, 2009 – $6.38 per unit right). The following assumptions were used to arrive at the estimate of fair values:

	Years Ended December 31	
	2010	2009
Expected annual exercise price reduction (on unit rights with declining exercise price)	**$2.16 - $2.40**	$1.44 - $2.16
Expected volatility	**43% - 44%**	39% - 43%
Risk-free interest rate	**1.99% - 3.02%**	1.78% - 2.72%
Forfeiture rate	**4.6%**	10.0%
Expected life of unit rights (years)(1)	**Various**	Various

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected lives of share rights or unit rights. The maximum term is limited to five years by the Share Rights Plan.

The following table is a summary of the status of the unvested share rights or unit rights as of December 31, 2010 and 2009 and changes during the years then ended:

	Number of unvested share rights or unit rights	Weighted average grant date fair value
Unvested, December 31, 2008	4,669	$ 3.03
Granted	1,844	$ 6.38
Vested	(2,227)	$ 3.38
Forfeited	(114)	$ 3.00
Unvested, December 31, 2009	4,172	$ 4.32
Granted	190	$ 9.03
Vested	(2,065)	$ 3.67
Forfeited	(212)	$ 3.81
Unvested, December 31, 2010	2,085	$ 4.49

As of December 31, 2010, there was $22.7 million of total unrecognized compensation cost (December 31, 2009 – $36.0 million) related to unvested share rights or unit rights; the cost is expected to be recognized over a weighted average period of 1.1 years. The total fair value of share rights or unit rights vested during the year ended December 31, 2010 was $39.6 million (year ended December 31, 2009 – $37.0 million).

The intrinsic value of a share right or unit right is the amount by which the current market value of the underlying common share or trust unit exceeds the exercise price of the share right or unit right.

The following tables summarize information related to share rights or unit rights activity during the years ended December 31, 2010 and 2009:

	Number of share rights or unit rights	Weighted average exercise price(1)	Weighted average remaining contract life (years)	Aggregate intrinsic value
Outstanding, December 31, 2009	8,120	$ 16.68	3.1	$ 105,720
Granted	190	32.71	4.3	36
Exercised	(2,337)	11.13	1.1	56,265
Forfeited	(212)	20.35	2.9	2,583
Outstanding, December 31, 2010	**5,761**	**$ 17.02**	**2.6**	**$ 170,483**
Exercisable, December 31, 2010	**3,676**	**$ 14.97**	**2.1**	**$ 116,310**
Expected to vest	**1,989**	**$ 20.63**	**3.5**	**$ 51,681**

	Number of unit rights	Weighted average exercise price(1)	Weighted average remaining contract life (years)	Aggregate intrinsic value
Outstanding, December 31, 2008	8,449	$ 14.58	3.3	$ 16,277
Granted	1,844	24.87	4.7	–
Exercised	(2,059)	9.97	1.5	29,468
Forfeited	(114)	16.43	3.2	508
Outstanding, December 31, 2009	**8,120**	**$ 16.68**	**3.1**	**$ 105,720**
Exercisable, December 31, 2009	**3,948**	**$ 13.22**	**2.1**	**$ 65,078**
Expected to vest	**3,755**	**$ 19.96**	**4.0**	**$ 36,578**

(1) Exercise price reflects the grant price less the reduction in exercise price as discussed above. During 2009, Baytex modified the terms of certain share rights or unit rights to re-set the exercise price to the greater of the original grant price and the closing price of the share rights or unit rights on trading day prior to the date of grant. This modification resulted in an increase of the weighted average exercise price per share right or unit right from $16.49 to $16.68.

(H) Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate current and future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The future income tax adjustments included in the Reconciliation of Net Income under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheets – U.S. GAAP include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The unrecognized tax benefits of the Company are disclosed below:

Unrecognized tax benefits, December 31, 2008	$ 3,600
Gross decrease for tax positions taken during a prior period	61
Gross increase for tax positions taken during a prior period	–
Gross decrease for tax positions taken during the current period	–
Gross increase for tax positions taken during the current period	(566)
Reductions due to lapse of applicable statute of limitations	(175)
Unrecognized tax benefits, December 31, 2009	$ 2,920
Gross decrease for tax positions taken during a prior period	–
Gross increase for tax positions taken during a prior period	–
Gross decrease for tax positions taken during a current period	(25)
Gross increase for tax positions taken during the current period	33,961
Reductions due to lapse of applicable statute of limitations	(904)
Unrecognized tax benefits, December 31, 2010	**$ 35,952**

All of the Company's unrecognized tax benefits at December 31, 2010, if recognized, would affect Baytex's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.

Baytex recognizes interest and penalties related to uncertain tax positions in a component of interest expense. Interest expense for the year ended December 31, 2010 did not include any interest and penalties related to taxation amounts (December 31, 2009 – $0.3 million). There are no accruals of interest and penalties as at December 31, 2010 and 2009 on the balance sheet.

Baytex and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax, or the relevant income tax in other international jurisdictions. Baytex may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the date of mailing of the original notice of assessment in respect of any particular taxation year. For the Canadian federal and provincial income tax matters, the open taxation years range from 2005 to 2010. The U.S. federal statute of limitations for assessment of income tax is generally closed for the taxation years through 2005. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. The federal tax authorities are currently auditing the income tax returns of two of Baytex's U.S. subsidiaries for the 2008 taxation year.

(I) Petroleum and Natural Gas Revenues

Under U.S. GAAP, petroleum and natural gas revenues are required to be presented net of royalties, excise and sales taxes to governments and other mineral interest owners.

(J) Interest

Under U.S. GAAP, interest income should be disclosed separately from interest expense on the face of the income statement. For the year ended December 31, 2010, interest income netted against the interest expense was $8 thousand (year ended December 31, 2009 – $0.1 million).

(K) Business Combinations

On May 26, 2010, Baytex completed an acquisition of a private company for a total consideration of $40.9 million funded with debt. Under U.S. GAAP, the cost associated with the acquisition of $0.6 million has been expensed as incurred.

(L) Consolidated Statement of Cash Flows

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

(M) Additional Disclosures

1. The components of accounts receivable are as follows:

	As at December 31	
	2010	2009
Petroleum and natural gas sales and accrual	$ 120,116	$107,657
Joint venture	30,536	28,581
Prepaid, deposits and other	2,993	3,252
Less: allowance for doubtful accounts	(1,853)	(2,336)
	$ 151,792	$137,154

2. The components of inventory are as follows:

	As at December 31	
	2010	2009
Petroleum and condensates	$ 1,744	$ 1,217
Other	58	167
	$ 1,802	$ 1,384

3. The components of accounts payable and accrued liabilities are as follows:

	As at December 31	
	2010	2009
Trade payables	$ 80,968	$ 81,387
Joint venture	12,284	23,564
Petroleum and natural gas accrued liabilities	71,502	63,500
Other	14,515	12,042
	$ 179,269	$ 180,493

(N) Commitments and Contingencies

For the year ended December 31, 2010, the Company recorded an expense for operating leases of $4.9 million (year ended December 31, 2009 – $2.9 million). The operating leases have expiration dates ranging from February 2011 to April 2020.

(O) Supplemental Information

Change in Non-Cash Working Capital Items

	Years ended December 31	
	2010	2009
Operating activities		
Accounts receivable	$ (8,079)	$ (39,565)
Crude oil inventory	(418)	(1,052)
Accounts payable and accrued liabilities	(1,544)	12,689
Foreign exchange on working capital	74	50
	(9,967)	(27,878)
Investing activities		
Accounts receivable	(4,839)	(10,038)
Accounts payable and accrued liabilities	(1,117)	3,451
	(5,956)	(6,587)
	$ (15,923)	$ (34,465)

(P) Recent Developments in U.S. Accounting

The following accounting pronouncement was adopted during 2010:

Amendments to Consolidation of Variable Interest Entities – intended to address (1) the effects on certain consolidation provisions as a result of the elimination of the concept of qualifying special-entities and (2) constituent concerns about the application of certain consolidation provisions including those in which the accounting and disclosures do not always provide timely and useful information about and enterprise's involvement in a variable interest entity. The adoption of the provisions on January 1, 2010 did not have any impact to the Company's consolidated results of operations, financial position or cash flows.

Future accounting pronouncements:

IFRS financial statements – the U.S. Securities and Exchange Commission has issued final rules to accept from foreign private issuers financial statements prepared in accordance with IFRS as issued by the International Accounting Standards Board without reconciliation to U.S. GAAP. Baytex, as a foreign private issuer, adopted IFRS on January 1, 2011.

Petroleum and Natural Gas Reserves as at December 31, 2010(1)

	Forecast Prices and Costs					
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserve Category	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
PROVED						
Developed Producing	7,011	5,764	35,751	29,030	2,057	1,461
Developed Non-Producing	634	509	14,610	12,281	337	247
Undeveloped	10,771	9,062	54,618	46,073	430	307
TOTAL PROVED	18,416	15,335	104,978	87,384	2,825	2,015
PROBABLE	17,943	14,957	62,435	51,284	1,215	863
TOTAL PROVED PLUS PROBABLE	36,359	30,292	167,414	138,668	4,040	2,878

	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent(4)	
Reserve Category	Gross(2)	Net(3)	Gross(2)	Net(3)
	(bcf)	*(bcf)*	*(mboe)*	*(mboe)*
PROVED				
Developed Producing	62.2	52.5	55,184	45,007
Developed Non-Producing	7.9	6.7	16,900	14,152
Undeveloped	13.7	11.1	68,106	57,290
TOTAL PROVED	83.8	70.3	140,190	116,449
PROBABLE	43.5	36.1	88,835	73,118
TOTAL PROVED PLUS PROBABLE	127.3	106.4	229,025	189,567

(1) Reserve information is prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101").

(2) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(3) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserve Reconciliation

Reconciliation of Gross Company Interest Reserves[(1)(2)] By Principal Product Type (Forecast Prices and Costs)

	Light and Medium Crude Oil			Heavy Oil		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
December 31, 2009	14,568	10,233	24,801	97,055	48,542	145,597
Extensions	4,931	9,073	14,005	14,142	2,533	16,675
Discoveries	–	–	–	93	38	131
Improved Recoveries	–	–	–	1,641	19,058	20,699
Technical Revisions	(219)	(2,764)	(2,983)	1,314	(8,252)	(6,938)
Acquisitions	754	1,381	2,135	1,483	772	2,255
Dispositions	–	–	–	(102)	(34)	(136)
Economic Factors	43	19	62	(213)	(222)	(434)
Production	(1,660)	–	(1,660)	(10,434)	–	(10,434)
December 31, 2010	18,416	17,943	36,359	104,978	62,435	167,414

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mmcf)*
December 31, 2009	2,818	1,501	4,318	89,659	44,090	133,748
Extensions	253	143	396	7,278	9,247	16,525
Discoveries	–	–	–	–	–	–
Improved Recoveries	–	–	–	–	–	1
Technical Revisions	554	(396)	158	11,088	(8,439)	2,648
Acquisitions	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–
Economic Factors	(74)	(32)	(106)	(4,015)	(1,445)	(5,460)
Production	(726)	–	(726)	(20,185)	–	(20,185)
December 31, 2010	2,825	1,216	4,040	83,825	43,453	127,278

	Oil Equivalent[(3)]		
	Proved	Probable	Proved + Probable
	(mboe)	*(mboe)*	*(mboe)*
December 31, 2009	129,384	67,624	197,007
Extensions	20,539	13,290	33,829
Discoveries	93	38	131
Improved Recoveries	1,641	19,058	20,699
Technical Revisions	3,497	(12,819)	(9,322)
Acquisitions	2,237	2,154	4,390
Dispositions	(102)	(34)	(136)
Economic Factors	(913)	(476)	(1,389)
Production	(16,185)	–	(16,185)
December 31, 2010	140,190	88,836	229,025

(1) Gross Company interest reserves include solution gas but do not include royalty interests.

(2) Reserve information as at December 31, 2010 and 2009 is prepared in accordance with NI 51-101.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserve Life Index

The following table sets forth our reserve life index based on total proved and proved plus probable reserves and the mid-point of our 2011 production guidance as at December 31, 2010 of 47,500 boe/d. This guidance was increased to a mid-point of 49,500 boe/d following the 2011 Heavy Oil Acquisition.

		Reserve Life Index (years)	
	2011 Production Target	Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	39,500	8.8	14.4
Natural Gas (mmcf/d)	48.0	4.8	7.3
Oil Equivalent (boe/d)	47,500	8.1	13.2

Net Present Value of Reserves (Forecast Prices and Costs)

	Summary of Net Present Value of Future Net Revenue As at December 31, 2010 Before Income Taxes and Discounted at (%/year)				
Reserve Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	2,037,270	1,684,270	1,460,841	1,304,643	1,187,953
Developed Non-Producing	616,756	453,024	346,684	274,295	223,029
Undeveloped	2,298,669	1,599,073	1,172,832	897,447	708,885
Total Proved	4,952,695	3,736,367	2,980,357	2,476,385	2,119,867
Probable	3,244,722	1,835,564	1,194,590	850,602	643,448
Total Proved Plus Probable	8,197,417	5,571,931	4,174,947	3,326,987	2,763,315

The net present values noted in the table above do not include any value for future net revenue which may ultimately be generated from the contingent resources.

Sproule December 31, 2010 Forecast Prices

Year	WTI Cushing *US$/bbl*	Edmonton Par Price *C$/bbl*	Hardisty Heavy 12 API *C$/bbl*	AECO C-Spot *C$/mmBtu*	Inflation Rate *%/Yr*	Exchange Rate *$US/$Cdn*
2010 act.	79.43	77.81	62.29	4.16	1.5%	0.97
2011	88.40	93.08	74.46	4.04	1.5%	0.93
2012	89.14	93.85	75.08	4.66	1.5%	0.93
2013	88.77	93.43	72.87	4.99	1.5%	0.93
2014	88.88	93.54	71.09	6.58	1.5%	0.93
2015	90.22	94.95	72.16	6.69	1.5%	0.93
2016	91.57	96.38	73.25	6.80	1.5%	0.93
2017	92.94	97.84	74.36	6.91	1.5%	0.93
2018	94.34	99.32	75.48	7.02	1.5%	0.93
2019	95.75	100.81	76.62	7.14	1.5%	0.93
2020	97.19	102.34	77.78	7.26	1.5%	0.93

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent reserve evaluator, Sproule, the efficiency of our capital programs, as measured by finding, development and acquisition ("FD&A") costs and operating netback per boe and recycle ratio, are summarized as follows:

	2010	2009	2008	Three Year Average 2008 - 2010
Excluding Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[1]	$ 9.54	$ 12.54	$ 14.26	$ 11.50
Acquisitions (net of dispositions)	21.84	21.27	22.99	22.32
Total	$ 10.52	$ 15.45	$ 18.37	$ 14.57
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[1]	$ 5.41	$ 9.25	$ 10.53	$ 7.39
Acquisitions (net of dispositions)	10.96	16.70	15.83	15.35
Total	$ 5.90	$ 11.63	$ 13.11	$ 9.54
Operating netback per boe[2]	$ 32.79	$ 27.64	$ 33.76	$ 31.42
Recycle ratio based on operating netback[2]				
Proved plus probable	5.6	2.4	2.6	3.3
Including Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[1]	$ 15.22	$ 22.96	$ 11.01	$ 16.06
Acquisitions (net of dispositions)	32.71	28.28	27.87	28.52
Total	$ 16.61	$ 24.73	$ 18.95	$ 19.59
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[1]	$ 12.44	$ 20.01	$ 12.09	$ 14.00
Acquisitions (net of dispositions)	20.68	23.12	20.23	21.09
Total	$ 13.17	$ 21.00	$ 16.06	$ 15.92
Recycle ratio based on operating netback[2]				
Proved plus probable	2.5	1.3	2.1	2.0

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

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

ABBREVIATIONS

AcSB	Accounting Standards Board
AECO	the natural gas storage facility located at Suffield, Alberta
ASC	Accounting Standards Codification
bbl	barrel
bbl/d	barrel per day
bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLB	Lloyd Light Blend
LLK	Lloyd Kerrobert
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
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MW	Megawatt
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Executive Chairman
Baytex Energy Corp.

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

Edward Chwyl (2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

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

Gregory K. Melchin (1)
Independent Businessman

Dale O. Shwed (3)
President & Chief Executive Officer
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

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BNP Paribas (Canada)
Canadian Imperial Bank of Commerce
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

OFFICERS

Raymond T. Chan
Executive Chairman

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,
Corporate Development

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 Development

R. Shaun Paterson
Vice President, Marketing

Richard P. Ramsay
Vice President, Heavy Oil

Mark F. Smith
Vice President, Conventional Oil & Gas

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE

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