BAYTEX
ENERGY CORP.

Q2 REPORT

2012

SUMMARY

- Produced 53,073 boe/d (86% oil and NGL) in Q2/2012, an increase of 11% over Q2/2011;
- Generated funds from operations ("FFO") of $124.7 million ($1.04 per basic share) in Q2/2012, a decrease of 10% from Q2/2011;
- Generated net income of $157.3 million ($1.32 per basic share) in Q2/2012, an increase of 47% over Q2/2011;
- Completed the sale of non-operated assets in North Dakota for net proceeds of $313.8 million (US$312 million), realizing a pre-tax gain of $175.4 million ($105.2 million net of current and deferred income tax);
- Maintained a conservative cash payout ratio in Q2/2012 of 42% net of dividend reinvestment plan ("DRIP") participation (63% before DRIP); and
- Subsequent to the end of the second quarter, issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par and called $150 million of 9.15% Series A senior unsecured debentures due 2016 for redemption.

	Three Months Ended			Six Months Ended	
	June 30, 2012	March 31, 2012	June 30, 2011	**June 30, 2012**	June 30, 2011
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**284,248**	343,355	336,899	**627,603**	627,214
Funds from operations(1)	**124,692**	141,736	138,233	**266,428**	247,703
Per share – basic	**1.04**	1.20	1.20	**2.24**	2.15
Per share – diluted	**1.03**	1.18	1.17	**2.20**	2.10
Cash dividends declared(2)	**51,943**	55,559	52,763	**107,502**	104,765
Cash dividends declared per share	**0.66**	0.66	0.60	**1.32**	1.20
Net income	**157,280**	42,958	106,863	**200,238**	107,813
Per share – basic	**1.32**	0.36	0.92	**1.68**	0.94
Per share – diluted	**1.30**	0.36	0.90	**1.66**	0.91
Exploration and development	**102,895**	135,918	108,453	**238,813**	195,467
Property acquisitions	**10,173**	2,336	(185)	**12,509**	37,333
Corporate acquisition	**–**	–	1,325	**–**	118,671
Proceeds from divestitures	**(313,834)**	(3,568)	–	**(317,402)**	–
Total oil and natural gas capital expenditures	**(200,766)**	134,686	109,593	**(66,080)**	351,471
Bank loan	**396,207**	326,889	315,073	**396,207**	315,073
Long-term debt	**302,865**	299,865	294,645	**302,865**	294,645
Working capital (surplus) deficiency	**(261,153)**	63,988	72,621	**(261,153)**	72,621
Total monetary debt(3)	**437,919**	690,742	682,339	**437,919**	682,339

	Three Months Ended			Six Months Ended	
	June 30, 2012	March 31, 2012	June 30, 2011	**June 30, 2012**	June 30, 2011
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**7,090**	7,565	6,055	**7,327**	6,329
Heavy oil (bbl/d)	**38,579**	38,353	33,839	**38,467**	32,821
Total oil and NGL (bbl/d)	**45,669**	45,918	39,894	**45,794**	39,150
Natural gas (mmcf/d)	**44.4**	45.1	47.8	**44.8**	49.4
Oil equivalent (boe/d @ 6:1)(4)	**53,073**	53,433	47,853	**53,254**	47,380
Average prices (before hedging)					
WTI oil (US$/bbl)	**93.49**	102.93	102.56	**98.20**	98.33
Edmonton par oil ($/bbl)	**84.42**	92.81	102.63	**88.55**	95.57
BTE light oil and NGL ($/bbl)	**71.62**	81.99	89.11	**76.97**	82.14
BTE heavy oil ($/bbl)(5)	**57.42**	65.89	71.02	**61.65**	65.60
BTE total oil and NGL ($/bbl)	**59.63**	68.54	73.78	**64.10**	68.26
BTE natural gas ($/mcf)	**2.00**	2.46	4.36	**2.23**	4.27
BTE oil equivalent ($/boe)	**52.97**	60.98	65.84	**57.00**	60.89
CAD/USD noon rate at period end	**1.0191**	0.9991	0.9643	**1.0191**	0.9643
CAD/USD average rate for period	**1.0102**	1.0003	0.9676	**1.0052**	0.9767
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**$ 53.61**	$ 59.40	$ 58.76	**$ 59.40**	$ 58.76
Low	**$ 38.54**	$ 50.52	$ 47.59	**$ 38.54**	$ 46.00
Close	**$ 42.89**	$ 51.79	$ 52.72	**$ 42.89**	$ 52.72
Volume traded (thousands)	**34,162**	23,378	22,857	**57,540**	57,055
NYSE					
Share price (US$)					
High	**$ 54.44**	$ 59.50	$ 61.95	**$ 59.50**	$ 61.95
Low	**$ 37.40**	$ 50.49	$ 48.63	**$ 37.40**	$ 46.25
Close	**$ 42.11**	$ 51.86	$ 54.44	**$ 42.11**	$ 54.44
Volume traded (thousands)	**8,257**	4,488	9,851	**12,745**	18,035
Common shares outstanding (thousands)	**119,914**	118,905	116,004	**119,914**	116,004

Notes:

(1) *Funds from operations is a non-GAAP measure that represents cash generated from operating activities adjusted for finance costs, changes in non-cash operating 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 six months ended June 30, 2012.*

(2) *Cash dividends declared are net of DRIP participation.*

(3) *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 deferred income tax assets or liabilities and unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans.*

(4) *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.*

(5) *Heavy oil prices are net of blending costs*

Forward-Looking Statements

This report contains forward-looking statements relating to: our average production rate for 2012; our exploration and development capital expenditures for 2012; our production mix for 2012, development plans for our properties, including the number of wells to be drilled in the remainder of 2012; initial production rates from wells drilled; our Cliffdale cyclic steam stimulation project at Seal, including our assessment of the steam and flowback operations, the cumulative steam-oil ratio for the project and our plan for a second commercial module of CSS; our Lloydminster heavy oil area, including the development potential of these properties, our ability to exploit multiple horizons and estimated 30-day peak productions rates from new horizontal and vertical wells; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate; the alleviation of pipeline constraints through the addition of incremental transportation capacity; the completion of refinery turnarounds; the demand for Canadian heavy oil by U.S. refiners; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; the volume of heavy oil to be transported to market on railways in 2012; the expected in-service date for a pipeline expansion that will enable us to access the U.S. Gulf Coast markets; the application of the proceeds from the sale of our non-operated interests in North Dakota; the amount of our undrawn credit facilities at June 30, 2012; our debt-to-FFO ratio; our pro forma financial position following the issuance of the Series C senior unsecured debentures, the redemption of the Series A senior unsecured debentures and the repatriation of the proceeds from the sale of our non-operated interests in North Dakota; our liquidity and financial capacity; and our ability to continue to execute our growth and income business model in a volatile commodity price environment. 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. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of FFO and capital expenditures 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 statements.

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.

All amounts in this report are stated in Canadian dollars unless otherwise noted.

MESSAGE TO SHAREHOLDERS

Operations Review

Production continued to perform in accordance with our operating budget, averaging 53,073 boe/d (86% oil and NGL) during Q2/2012. This production rate represents an increase of 11% over Q2/2011, which growth is essentially attributable to our exploration and development program. The current quarter production also compares favourably to the 53,433 boe/d average in Q1/2012, after accounting for the approximately 440 boe/d impact on the quarter average from the North Dakota disposition, and the usual production curtailment associated with spring break-up field conditions. Our 2012 annual production guidance remains at 53,500 to 54,500 boe/d and our 2012 exploration and development capital budget remains at $400 million. Our production mix for 2012 is forecast to be 73% heavy oil, 14% light oil and NGL and 13% natural gas.

Capital expenditures for exploration and development activities totaled $102.9 million for Q2/2012. During the quarter, Baytex participated in the drilling of 38 (22.9 net) wells with a 100% success rate.

Wells Drilled in Q2/2012

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster area	10	6.1	–	–	–	–	–	–	–	–	10	6.1
Peace River area	11	11.0	–	–	–	–	–	–	–	–	11	11.0
	21	**17.1**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**21**	**17.1**
Light oil, NGL and natural gas												
Western Canada	3	2.1	–	–	–	–	–	–	–	–	3	2.1
North Dakota	14	3.7	–	–	–	–	–	–	–	–	14	3.7
	17	**5.8**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**17**	**5.8**
Total	**38**	**22.9**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**38**	**22.9**

Heavy Oil

In Q2/2012, heavy oil production averaged 38,579 bbl/d, an increase of 14% over Q2/2011 and 1% over Q1/2012. During the current quarter, we drilled 21 (17.1 net) oil wells on our heavy oil properties with a success rate of 100%.

Production from our Peace River area properties averaged approximately 19,300 bbl/d in Q2/2012, an increase of 4% over Q1/2012 and 34% over Q2/2011. In this quarter, we drilled 11 (11.0 net) cold horizontal producers in the Seal area (encompassing a total of 139 laterals). During the quarter, 10 Seal wells established average 30-day peak production rates of approximately 575 bbl/d and one Reno well established a 30-day peak production rate of 300 bbl/d. We plan to drill approximately 22 cold horizontal wells in the Peace River area in the remainder of the year.

In the Cliffdale area of Seal, successful operations continued at our 10-well commercial cyclic steam stimulation ("CSS") module, with production during the second quarter averaging 440 bbl/d, consistent with project design parameters. During Q2/2012, two wells received steam and four wells commenced post-steam flowback operations. First-cycle peak rates of 230 bbl/d and second-cycle peak rates of 325 bbl/d were observed. Thermal flowback operations on the original pilot well generated a fourth-cycle peak rate of 390 bbl/d with a significant increase in sustained average daily production rates. The final five CSS wells that were completed during the first quarter of 2012 continued their initial cold-production phase, a process designed to generate reservoir voidage prior to first steam. First-cycle steaming for these remaining five wells will commence in the second half of 2012. To date, the Cliffdale project has demonstrated a cumulative steam-oil-ratio of less than 1.9 barrels of steam per barrel of oil. Subject to receipt of regulatory approvals, we plan to initiate development of a new 15-well commercial CSS module during Q4/2012.

Second quarter drilling included five (5.0 net) horizontal wells and five (1.1 net) vertical wells in our Lloydminster heavy oil area. This area is characterized by stacked pay which has lead to successful exploitation of multiple horizons. Our Lloydminster heavy oil projects generate consistent, repeatable results with horizontal wells typically producing 30-day peak rates of approximately 70-80 bbl/d and vertical wells typically producing 30-day peak rates of approximately 30-40 bbl/d. We expect to drill approximately 11 horizontal wells and 18 vertical wells in this area in the second half of 2012.

Light Oil & Natural Gas

During Q2/2012, light oil, NGL and natural gas production averaged 14,494 boe/d, which was comprised of 7,090 bbl/d of light oil and NGL and 44.4 mmcf/d of natural gas. Compared to Q2/2011, light oil and NGL production increased 17% and natural gas production decreased 7%. Compared to the Q1/2012, light oil and NGL production decreased 6%, reflecting the sale of the non-operated North Dakota assets, and natural gas production decreased 2%.

On May 22, 2012, Baytex completed the sale of its non-operated interests in North Dakota for cash proceeds of US$312 million, after closing adjustments. The assets included approximately 950 boe/d of Bakken light oil production (based on Q1/2012 production) and 149,700 (50,400 net) acres of land, of which approximately 24% was developed. This sale represented 45% of our North Dakota net acreage and approximately 40% of our U.S. production. These assets were not a primary focus of our U.S. Business Unit as they were non-operated and generally had a lower average working interest than our remaining lands.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of 14 (3.7 net) horizontal oil wells during Q2/2012, six of which were Baytex-operated, and the fracture-stimulation of 14 (2.7 net) wells. During the quarter, 18 Baytex-interest 1,280-acre spacing wells established average 30-day peak rates of approximately 310 bbl/d. We plan to drill approximately 12 (4.0 net) wells in North Dakota during the remainder of 2012.

During Q2/2012, Baytex entered into an agreement to acquire approximately 72,300 (50,600 net) acres (70% working interest) in Weston and Niobrara Counties, Wyoming for US$176 per net acre (total initial consideration of US$8.9 million). Baytex is in the process of permitting two horizontal wells to test the Turner formation, which produces from existing vertical wells in the area and is being developed with horizontal techniques elsewhere in the basin. Baytex will complete its obligations under this agreement by carrying the seller for a 30% working interest in these two wells, estimated to cost approximately US$4 million per well on a 100% basis.

During Q2/2012, we drilled two horizontal wells in our Viking light oil resource play in Central Alberta, with one well drilled in Q1/2012 and one well drilled in Q2/2012 establishing average 30-day peak rates of 80 bbl/d. We have five Viking wells planned for the second half of 2012.

Financial Review

We generated FFO of $125 million ($1.04 per basic share) in Q2/2012, a decrease of 10% compared to Q2/2011, and a decrease of 12% compared to Q1/2012, both due to lower realized prices for oil and natural gas. Revenue, net of royalties, were $238.2 million in Q2/2012, a 17% decrease from Q2/2011 due in part to the increase in sales volumes which were delivered to market on railways. Unlike pipelines, heavy oil transported on railways does not need to be blended with condensate. As a result, we sell an unblended barrel, the price of which does not include the cost of the blending diluent. Correspondingly, our transportation and blending expenses are 29% lower in Q2/2012 than they were in Q2/2011 as we did not have to purchase as much condensate for blending. Our sales price, net of blending cost, is enhanced by transporting heavy oil on railways, but from a reporting perspective, there is a reduction in gross revenue and a reduction in transportation and blending expenses.

The average WTI price for Q2/2012 was US$93.49, a 9% decrease from both Q2/2011 and Q1/2012. We received an average oil and NGL price of $59.63/bbl in Q2/2012 (inclusive of our physical hedging gains), down 19% from $73.78/bbl for Q2/2011 and down 13% from $68.54/bbl for Q1/2012. We received an average natural gas price of $2.00/mcf in Q2/2012, down 54% from $4.36/mcf for Q2/2011 and down 19% from $2.46/mcf for Q1/2012.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 24% during Q2/2012, and 22% for the first half of 2012, as compared to 17% and 21%, respectively, for the same periods in 2011. The increase in Canadian heavy crude differentials in Q2/2012, as compared to Q2/2011, was caused by operational issues at export pipelines and U.S. refineries that run Canadian heavy oil. Demand for Canadian heavy oil is expected to remain strong in the future, with additional refinery expansions in late 2012 and in 2013, together with increasing rail exports of Canadian heavy oil and increasing pipeline access to U.S. gulf coast refineries. However, sporadic refinery and export pipeline upsets, together with growing heavy oil production, increase the likelihood of continued volatility in WCS price differentials from month-to-month. Current prompt WCS differential to WTI is approximately 17%, with a forward strip suggesting approximately 24% for the second half of 2012. Over the longer term, we continue to believe that transportation solutions to allow Canadian crudes to access additional markets will proceed, and that the prices for Canadian crudes will more closely match those of worldwide quality peers.

Baytex continues to actively hedge its exposure to commodity prices and foreign exchange rates. We have established forward contracts for the balance of 2012 on approximately 43% of our WTI price exposure, 28% of our heavy oil differential exposure, 38% of our natural gas price exposure, and 32% of our exposure to currency movements between the Canadian and U.S. dollars. We have begun to secure hedging contracts on our WTI exposure for 2013. Details of all hedging contracts are contained in the notes to our interim financial statements. We continue to monitor the markets for opportunities to add to our hedge positions.

Our WCS differential hedges are primarily contracts that provide a fixed dollar differential to WTI. Based on the forward strip for WTI, our WCS contracts for 2012 translate to approximately an 18% differential to WTI. We have additional contracts for smaller volumes in place for 2013 and 2014 at an average differential of 21% to WTI. In addition to our hedging program, we are also mitigating our exposure to WCS differentials by transporting crude oil to higher value markets by railways. We are currently delivering approximately 27% of our heavy oil volumes to market by rail and expect to increase rail deliveries to approximately 35% to 40% of our heavy oil volumes by year-end. Furthermore, as part of our long-term transportation portfolio, we have entered into a transportation services agreement for a pipeline expansion that will enable us to access the U.S. gulf coast markets for approximately 12% of our heavy oil production (based on current production rates) for a 10-year period. This pipeline expansion is expected to commence service in mid-2014.

During Q2/2012, Baytex completed the previously disclosed sale of non-operated interests in North Dakota for net proceeds of $313.8 million (US$312 million), realizing a pre-tax gain of $175.4 million. Cash tax expense of $17 million has been accrued in the second quarter related to this disposition. Under U.S. income tax laws, if the proceeds of a disposition are reinvested into qualifying properties within a prescribed time frame, the tax on the gain may be deferred. In order to qualify for this potential deferral, we were required to place the sales proceeds into escrow pending the acquisition of replacement properties. Subsequent to the end of the second quarter, US$112.5 million of the sales proceeds were returned from escrow and used to reduce borrowings on our credit facilities. The balance of US$199.5 million will either be invested in replacement properties in the U.S. or remain in escrow until Q4/2012, at which time it will be released and used to reduce borrowings on our credit facilities. At this time it is not likely we will conclude a transaction to acquire qualifying replacement properties within the prescribed time frame and, therefore, the tax accrued will become payable as installments in the third and fourth quarters of 2012.

We ended the quarter with total monetary debt of $438 million representing a debt-to-FFO ratio of 0.8 times, based on FFO over the trailing twelve-month period. In July 2012, we issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. A portion of the net proceeds of this issue will be used to redeem $150 million of 9.15% Series A senior unsecured debentures, which have been called for redemption on August 26, 2012 at 104.575% of principal amount, with the remaining proceeds used to reduce borrowings on our credit facilities. Pro forma the debenture issue in July and the debenture redemption in August, and assuming the repatriation of all of the North Dakota sales proceeds (net of tax), the only outstanding borrowings Baytex would have are the US$150 million Series B debentures due 2021 and the $300 million Series C debentures due 2022. Our entire $700 million credit facilities would be undrawn.

Conclusion

Baytex's operations continue to advance in accordance with our business plans and budgets, underpinned by a proven asset base and dedicated employees led by a talented management team. Proceeds from the sale of non-operated assets in North Dakota, combined with the issuance of new 10-year senior unsecured debentures in July, create a balance sheet that provides us with ample liquidity to support the execution of our growth and income business model. We look forward to welcoming our new President and Chief Executive Officer, Jim Bowzer, in September and continuing to deliver superior returns to our shareholders.

On behalf of the Board of Directors,

Raymond T. Chan
Executive Chairman and Interim Chief Executive Officer
August 14, 2012

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 three months and six months ended June 30, 2012. This information is provided as of August 13, 2012. 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. The second quarter results have been compared with the corresponding period in 2011. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three months and six months ended June 30, 2012 and 2011, its audited consolidated comparative financial statements for the years ended December 31, 2011 and 2010, together with accompanying notes, and its Revised Annual Information Form for the year ended December 31, 2011. These documents and additional information about Baytex are accessible on the SEDAR website 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 percentages and per common share amounts 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.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with GAAP, such as 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 Dividends".

Payout Ratio

We define payout ratio as cash dividends (net of participation in our dividend reinvestment plan) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

RESULTS OF OPERATIONS

Production

	Three Months Ended June 30			Six Months Ended June 30		
	2012	2011	Change	**2012**	2011	Change
Daily Production						
Light oil and NGL (bbl/d)	**7,090**	6,055	17%	**7,327**	6,329	16%
Heavy oil (bbl/d)[(1)]	**38,579**	33,839	14%	**38,467**	32,821	17%
Natural gas (mmcf/d)	**44.4**	47.8	(7%)	**44.8**	49.4	(9%)
Total production (boe/d)	**53,073**	47,853	11%	**53,254**	47,380	12%
Production Mix						
Light oil and NGL	**13%**	13%	–	**14%**	14%	–
Heavy oil	**73%**	71%	–	**72%**	69%	–
Natural gas	**14%**	16%	–	**14%**	17%	–

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes to Baytex's heavy oil inventory. For the three months ended June 30, 2012, heavy oil sales volumes were 88 bbl/d lower than production volumes (three months ended June 30, 2011 – 71 bbl/d higher). For the six months ended June 30, 2012, heavy oil sales volumes were 1 bbl/d higher than production volumes (six months ended June 30, 2011 – 332 bbl/d higher).*

Production for the three months ended June 30, 2012 averaged 53,073 boe/d, compared to 47,853 boe/d for the same period in 2011. Light oil and natural gas liquids ("NGL") production increased by 17% to 7,090 bbl/d in the second quarter of 2012 from 6,055 bbl/d in the second quarter of 2011 due to development activities in the U.S., and production interruptions in 2011 from wet weather in North Dakota, as well as forest fires, and pipeline curtailments in Alberta. Light oil and NGL production was also impacted by an asset sale which reduced light oil production by an average of approximately 440 bbl/d in the current quarter. Heavy oil production for the second quarter of 2012 increased by 14% to 38,579 bbl/d from 33,839 bbl/d a year ago primarily due to development activities. Natural gas production decreased by 7% to 44.4 mmcf/d for the second quarter of 2012, as compared to 47.8 mmcf/d for the same period in 2011 primarily due to natural declines as we focused our capital spending on our oil portfolio.

Production for the six months ended June 30, 2012 averaged 53,254 boe/d, compared to 47,380 boe/d for the same period in 2011. Light oil and NGL production increased by 16% to 7,327 bbl/d from 6,329 bbl/d due to similar reasons listed above for the quarter-over-quarter comparison. Light oil and NGL production was also reduced by an average of approximately 220 bbl/d due to an asset sale. Heavy oil production for the six month ended June 30, 2012 increased by 17% to 38,467 bbl/d from 32,821 bbl/d a year ago primarily due to development activities. Natural gas production decreased by 9% to 44.8 mmcf/d for the first six months of 2012, as compared to 49.4 mmcf/d for the same period in 2011 primarily due to natural declines as we focused our capital spending on our oil portfolio.

Commodity Prices

Crude Oil

For the first six months of 2012, the price of prompt West Texas Intermediate ("WTI") fluctuated between a low of US$78.10/bbl and a high of US$110.56/bbl, resulting in a six-month average price of US$98.20/bbl, similar to the US$98.33/bbl average price for the first half of 2011. Several factors caused the oil price fluctuation seen in the first half of 2012. Through April 2012, a combination of escalating tensions over Iran's nuclear program and signs of improving economic conditions in the U.S. and developing world resulted in daily WTI prices of over US$100/bbl. In the second quarter of 2012, the average price of WTI fell to US$93.49/bbl, or 10% lower than the first quarter of 2012, on news of worsening financial situations in the European Union, as well as softening economic growth in the U.S. and China. Driven by prospects of lower global economic growth, as well as high production rates from Saudi Arabia, WTI prices declined for much of the second quarter to a low of US$78.10/bbl on June 28, 2012.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 24% during the second quarter of 2012, and 22% for the first half of 2012, as compared to 17% and 21%, respectively, for the same periods in 2011. The increase in Canadian heavy crude differentials in the second quarter of 2012, as compared to 2011 was primarily caused by operational issues at export pipelines and U.S. refineries that run Canadian heavy oil. Demand for Canadian heavy oil is expected to remain strong in the future, with additional refinery expansions in late 2012 and in 2013, together with increasing rail exports of Canadian heavy oil and increasing pipeline access to U.S. gulf coast refineries. However, sporadic refinery and export pipeline upsets, together with growing heavy oil production, increase the likelihood of continued volatility of heavy oil differentials from month-to-month.

Natural Gas

For the six months ended June 30, 2012, the average AECO natural gas price was $2.18/mcf, as compared to $3.76/mcf in the same period in 2011. For the three months ended June 30, 2012, AECO natural gas prices averaged $1.84/mcf, compared to $3.74/mcf in the same period last year. High U.S. natural gas production, combined with a relatively mild winter in major consuming areas, is largely responsible for the decline in natural gas prices seen through the first half of 2012, as storage levels in both the U.S. and western Canada set new records. In the later half of the second quarter in 2012, early and sustained hot weather across much of the U.S. increased power demand, particularly from gas-fired power generation. This in turn increased consumption of natural gas and depleted excess natural gas storage to help rally prices towards the end of the second quarter.

	Three Months Ended June 30			Six Months Ended June 30		
	2012	2011	Change	**2012**	2011	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**$ 93.49**	$ 102.56	(9%)	**$ 98.20**	$ 98.33	0%
WCS heavy oil (US$/bbl)[2]	**$ 70.62**	$ 84.93	(17%)	**$ 76.06**	$ 78.08	(3%)
Heavy oil differential[3]	**(24%)**	(17%)	–	**(22%)**	(21%)	–
CAD/USD average exchange rate	**1.0191**	0.9677	(5%)	**0.9947**	0.9768	(2%)
Edmonton par oil ($/bbl)	**$ 84.42**	$ 102.63	(18%)	**$ 88.55**	$ 95.57	(7%)
AECO natural gas price ($/mcf)[4]	**$ 1.84**	$ 3.74	(51%)	**$ 2.18**	$ 3.76	(42%)
Baytex Average Sales Prices						
Light oil and NGL ($/bbl)	**$ 71.62**	$ 89.11	(20%)	**$ 76.97**	$ 82.14	(6%)
Heavy oil ($/bbl)[5]	**$ 56.31**	$ 70.75	(20%)	**$ 60.38**	$ 64.47	(6%)
Physical forward sales contracts gain (loss) ($/bbl)	**1.11**	0.27		**1.27**	1.13	
Heavy oil, net ($/bbl)	**$ 57.42**	$ 71.02	(19%)	**$ 61.65**	$ 65.60	(6%)
Total oil and NGL, net ($/bbl)	**$ 59.63**	$ 73.78	(19%)	**$ 64.10**	$ 68.26	(6%)
Natural gas ($/mcf)[6]	**$ 2.00**	$ 4.04	(50%)	**$ 2.23**	$ 3.98	(44%)
Physical forward sales contracts gain ($/mcf)	**–**	0.21		**–**	0.29	
Natural gas, net ($/mcf)	**$ 2.00**	$ 4.36	(54%)	**$ 2.23**	$ 4.27	(48%)
Summary						
Weighted average ($/boe)[6]	**$ 52.04**	$ 65.26	(20%)	**$ 55.94**	$ 59.63	(6%)
Physical forward sales contracts gain (loss) ($/boe)	**0.93**	0.58		**1.06**	1.26	
Weighted average, net ($/boe)	**$ 52.97**	$ 65.84	(20%)	**$ 57.00**	$ 60.89	(6%)

(1) WTI refers to the arithmetic 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 arithmetic average 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 above pricing information in the table excludes the impact of financial derivatives.

During the second quarter of 2012, Baytex's average sales price for light oil and NGL was $71.62 bbl, down 20% from $89.11/bbl in the second quarter of 2011. Baytex's realized heavy oil price during the second quarter of 2012, prior to physical forward sales contracts, was $56.31/bbl, or 78% of WCS. This compares to a realized heavy oil price in the second quarter of 2011, prior to physical forward sales contracts, of $70.75/bbl, or 86% of WCS. The discount 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 second quarter of 2012 was $57.42/bbl, down 19% from $71.02/bbl in the second quarter of 2011. Baytex's realized natural gas price for the three months ended June 30, 2012 was $2.00/mcf with no applicable physical forward sales contracts (three months ended June 30, 2011 – $4.04/mcf prior to physical forward sales contracts and $4.36/mcf inclusive of physical forward sales contracts).

In the first six months of 2012, Baytex's average sales price for light oil and NGL was $76.97/bbl, down 6% from $82.14/bbl in the first six months of 2011. Baytex's realized heavy oil price during the first six months of 2012, prior to physical forward sales contracts, was $60.38/bbl or 80% of WCS. This compares to a realized heavy oil price in the first six months of 2011, prior to physical forward sales contracts, of $64.47/bbl, or 85% 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 first six months of 2012 was $61.65/bbl, down 6% from $65.60/bbl in the first six months of 2011. Baytex's realized natural gas price for the six months ended June 30, 2012 was $2.23/mcf with no applicable physical forward sales contracts (six months ended June 30, 2011 – $3.98/mcf prior to physical forward sales contracts and $4.27/mcf inclusive of physical forward sales contracts).

Gross Revenues

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for %)	**2012**	2011	Change	**2012**	2011	Change
Oil revenue						
Light oil and NGL	**$ 46,206**	$ 49,097	(6%)	**$ 102,649**	$ 94,091	9%
Heavy oil	**201,130**	217,882	(8%)	**431,635**	392,352	10%
Total oil revenue	**247,336**	266,979	(7%)	**534,284**	486,443	10%
Natural gas revenue	**8,086**	18,957	(57%)	**18,162**	38,193	(52%)
Total oil and natural gas revenue	**255,422**	285,936	(11%)	**552,446**	524,636	5%
Sales of heavy oil blending diluent	**28,826**	50,963	(43%)	**75,157**	102,578	(27%)
Total petroleum and natural gas sales	**$ 284,248**	$ 336,899	(16%)	**$ 627,603**	$ 627,214	–%

Petroleum and natural gas sales decreased 16% to $284.2 million for the three months ended June 30, 2012 from $336.9 million for the same period in 2011. This decrease is a result of lower oil and natural gas sales prices, which was partially offset by an increase in heavy and light oil and NGL sales volumes compared to the three months ended June 30, 2011. Sales of heavy oil blending diluent were down 43% for the three months ended June 30, 2012 from the same period last year because of the increase in our sales volumes which were delivered by rail. Unlike our sales through oil pipelines, when we sell raw bitumen by rail we are not required to blend it with condensate.

For the six months ended June 30, 2012, petroleum and natural gas sales totaled $627.6 million, consistent with $627.2 million for the same period in 2011. Lower realized oil and natural gas sales prices during the six months ended June 30, 2012 were offset by higher sales volumes as compared to the six months ended June 30, 2011. Sales of heavy oil blending diluent were down 27% for the six months ended June 30, 2012 from the same period last year because of the increase in our sales volumes which were delivered by rail. Unlike our sales through oil pipelines, when we sell raw bitumen by rail we are not required to blend it with condensate.

Royalties

($ thousands except for % and per boe)	Three Months Ended June 30 2012	2011	Change	Six Months Ended June 30 2012	2011	Change
Royalties	$ 46,020	$ 51,159	(10%)	$ 99,014	$ 99,961	(1%)
Royalty rates:						
Light oil, NGL and natural gas	18.3%	17.0%	–	18.4%	17.9%	–
Heavy oil	17.9%	18.2%	–	17.8%	19.4%	–
Average royalty rates(1)	18.0%	17.9%	–	17.9%	19.1%	–
Royalty expenses per boe	$ 9.54	$ 11.78	(19%)	$ 10.22	$ 11.60	(12%)

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

Total royalties for the second quarter of 2012 decreased to $46.0 million from $51.2 million in the second quarter of 2011. Total royalties for the second quarter of 2012 were 18.0% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 17.9% for the same period in 2011. Total royalties for the six months ended June 30, 2012 decreased to $99.0 million from $100.0 million in the six months ended June 30, 2011. Total royalties for the first six months of 2012 were 17.9% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 19.1% for the same period in 2011.

Royalty rates for light oil, NGL and natural gas increased from 17.0% in the three months ended June 30, 2011 to 18.3% in the three months ended June 30, 2012 due to expiry of conventional oil royalty rate incentives on new wells and timing differences from our gas cost allowance annual filings. Royalty rates for heavy oil decreased from 18.2% in the three months ended June 30, 2011 to 17.9% for the three months ended June 30, 2012 due to a lower Saskatchewan Resource Surcharge.

Royalty rates for light oil, NGL and natural gas increased from 17.9% in the six months ended June 30, 2011 to 18.4% in the six months ended June 30, 2012 due to expiry of conventional oil royalty rate incentives on new wells. Royalty rates for heavy oil decreased from 19.4% in the six months ended June 30, 2011 to 17.8% in the six months ended June 30, 2012 due to royalty incentives on new wells at Seal and Kerrobert. In Seal, the royalty framework levies a flat 5% royalty rate on horizontal wells for the first 50,000 to 100,000 barrels of production, depending on well depth. In Kerrobert, our Steam Assisted Gravity Drainage projects attract favourable royalty rate incentives.

Financial Derivatives

($ thousands)	Three Months Ended June 30 2012	2011	Change	Six Months Ended June 30 2012	2011	Change
Realized gain (loss) on financial derivatives(1)						
Crude oil	$ 7,688	$ (13,036)	$ 20,724	$ (865)	$ (17,469)	$ 16,604
Natural gas	1,763	(33)	1,796	2,988	(43)	3,031
Foreign currency	917	4,692	(3,775)	2,798	10,794	(7,996)
Interest rate	112	–	112	(1,581)	(72)	(1,509)
Total	$ 10,480	$ (8,377)	$ 18,857	$ 3,340	$ (6,790)	$ 10,130
Unrealized gain (loss) on financial derivatives(2)						
Crude oil	$ 53,309	$ 52,384	$ 925	$ 44,391	$ 3,593	$ 40,798
Natural gas	(1,976)	1,097	(3,073)	(1,608)	1,505	(3,113)
Foreign currency	(2,893)	(4,077)	1,184	419	(2,697)	3,116
Interest rate	(1,056)	198	(1,254)	(20)	731	(751)
Total	$ 47,384	$ 49,602	$ (2,218)	$ 43,182	$ 3,132	$ 40,050
Total gain (loss) on financial derivatives						
Crude oil	$ 60,997	$ 39,348	$ 21,649	$ 43,526	$ (13,876)	$ 57,402
Natural gas	(213)	1,064	(1,277)	1,380	1,462	(82)
Foreign currency	(1,976)	615	(2,591)	3,217	8,097	(4,880)
Interest rate	(944)	198	(1,142)	(1,601)	659	(2,260)
Total	$ 57,864	$ 41,225	$ 16,639	$ 46,522	$ (3,658)	$ 50,180

(1) Realized gain (loss) on financial derivatives represents actual cash settlement or receipts for the financial derivatives.
(2) Unrealized gain (loss) on financial derivatives represents the change in fair value of the financial derivatives during the period.

The total gain on financial derivatives for the three months ended June 30, 2012 was $57.9 million, as compared to a gain of $41.2 million for the same period in 2011. This includes a realized gain of $10.5 million and an unrealized mark-to-market gain of $47.4 million for the second quarter of 2012, as compared to $8.4 million in realized losses and an unrealized mark-to-market gain of $49.6 million for the second quarter of 2011. The realized gain of $10.5 million for the three months ended June 30, 2012 on derivative contracts relates to lower commodity prices during the period. The unrealized mark-to-market gain of $47.4 million for the three months ended June 30, 2012 relates to lower oil prices at June 30, 2012, as compared to December 31, 2011, partially offset by a weakening Canadian dollar against the U.S. dollar.

The total gain on financial derivatives for the six months ended June 30, 2012 was $46.5 million, as compared to a loss of $3.7 million for the same period in 2011. This includes a realized gain of $3.3 million and an unrealized mark-to-market gain of $43.2 million for the first six months of 2012, as compared to a $6.8 million realized loss and an unrealized mark-to-market gain of $3.1 million for the same period of 2011. The realized gain of $3.3 million for the six months ended June 30, 2012 relates to lower oil prices and favourable foreign currency contracts, partially offset by losses on oil and interest rate contracts. The unrealized mark-to-market gain of $43.2 million for the six months ended June 30, 2012 relates to lower natural gas prices at June 30, 2012, as compared to December 31, 2011, partially offset by a weakening Canadian dollar against the U.S. dollar.

A summary of the risk management contracts in place as at June 30, 2012 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

Evaluation and Exploration Expense

Evaluation and exploration expense for the three months ended June 30, 2012 increased to $4.5 million from $3.4 million for the same period in 2011 due to an increase in the expiration of undeveloped land leases. Evaluation and exploration expense for the six months ended June 30, 2012 increased marginally to $6.9 million from

$6.8 million for the same period in 2011. The increase in the second quarter of 2012 was offset by a decrease in the first quarter, resulting in no significant change for the six months ended June 30, 2012 as compared to 2011.

Production and Operating Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2012**	2011	Change	**2012**	2011	Change
Production and operating expenses	**$ 56,967**	$ 50,189	14%	**$ 115,254**	$ 97,665	18%
Production and operating expenses per boe:						
Heavy oil	**$ 10.62**	$ 11.31	(6%)	**$ 10.84**	$ 11.18	(3%)
Light oil, NGL and natural gas	**$ 14.99**	$ 12.14	23%	**$ 14.63**	$ 11.69	25%
Total	**$ 11.81**	$ 11.56	2%	**$ 11.89**	$ 11.34	5%

Production and operating expenses for the three months ended June 30, 2012 increased to $57.0 million from $50.2 million due to increased production volumes attributable to the development of existing assets in Canada and the U.S. Production and operating expenses were $11.81 per boe for the three months ended June 30, 2012, as compared to $11.56 per boe for the same period in 2011. Total production and operating expenses increased by 14% and light oil, NGL and natural gas production and operating expenses increased by 27% for the three months ended June 30, 2012, as compared to the same period of 2011 due to higher production and increased turnaround costs and labour rates.

Production and operating expenses for the six months ended June 30, 2012 increased to $115.3 million from $97.7 million due to increased production volumes attributable to the development of existing assets in Canada and the U.S. and from the Reno and Brewster acquisitions completed in February and August 2011, respectively. Production and operating expenses were $11.89 per boe for the six months ended June 30, 2012, as compared to $11.34 per boe for the same period in 2011. Total production and operating expenses increased by 18% and light oil, NGL and natural gas production and operating expenses increased by 28% for the six months ended June 30, 2012, as compared to the same period of 2011 due to higher production and increased workover expenses, turnaround costs and labour rates.

Transportation and Blending Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2012**	2011	Change	**2012**	2011	Change
Blending expenses	**$ 28,826**	$ 50,963	(43%)	**$ 75,157**	$ 102,578	(27%)
Transportation expenses	**18,964**	16,555	15%	**34,370**	29,100	18%
Total transportation and blending expenses	**$ 47,790**	$ 67,518	(29%)	**$ 109,527**	$ 131,678	(17%)
Transportation expenses per boe[(1)]:						
Heavy oil	**$ 5.18**	$ 5.04	3%	**$ 4.66**	$ 4.52	3%
Light oil, NGL and natural gas	**$ 0.61**	$ 0.85	(28%)	**$ 0.66**	$ 0.78	(15%)
Total	**$ 3.93**	$ 3.81	3%	**$ 3.55**	$ 3.38	5%

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

Transportation and blending expenses for the second quarter of 2012 were $47.8 million, as compared to $67.5 million for the second quarter of 2011. Transportation and blending expenses for the first half of 2012 were $109.5 million, as compared to $131.7 million for the first half of 2011.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. In most cases, Baytex purchases condensate from industry producers as the blending diluent facilitates the marketing of its heavy oil. In the second quarter of 2012, blending expenses were $28.8 million for the purchase of 3,114 bbl/d of condensate at $101.73 per barrel, as compared to $51.0 million for the purchase of 5,208 bbl/d at

$107.53 per barrel for the same period last year. In the six months ended June 30, 2012, blending expenses were $75.2 million for the purchase of 3,867 bbl/d of condensate at $106.79 per barrel, as compared to $102.6 million for the purchase of 5,537 bbl/d at $102.35 per barrel for the same period last year. This decrease in blending for both the three and six month periods ending June 30, 2012 is due to the export of a portion of our heavy oil production by rail, which does not require diluent blending, as compared to no rail exports in the prior periods. The cost of blending diluent is effectively recovered in the sale price of a blended product.

Transportation expenses were $3.93 per boe for the three months ended June 30, 2012, as compared to $3.81 per boe for the same period of 2011. Transportation expenses were $3.55 per boe for the six months ended June 30, 2012, as compared to $3.38 per boe for the same period of 2011. The increase in transportation expenses per barrel of heavy oil for the three and six months ended June 30, 2012 is primarily driven by a larger portion of our heavy oil production coming from our Seal and Reno areas which utilize long-haul trucking to ship a portion of production volumes.

Operating Netback

	Three Months Ended June 30			Six Months Ended June 30		
($ per boe except for % and volume)	**2012**	2011	Change	**2012**	2011	Change
Sales volume (boe/d)	**52,985**	47,725	11%	**53,255**	47,603	12%
Operating netback[(1)]:						
Sales price[(2)]	**$ 52.97**	$ 65.84	(20%)	**$ 57.00**	$ 60.89	(6%)
Less:						
Royalties	**9.54**	11.78	(19%)	**10.22**	11.60	(12%)
Operating expenses	**11.81**	11.56	2%	**11.89**	11.34	5%
Transportation expenses	**3.93**	3.81	3%	**3.55**	3.38	5%
Operating netback before financial derivatives	**$ 27.69**	$ 38.69	(28%)	**$ 31.34**	$ 34.57	(9%)
Financial derivatives gain (loss)[(3)]	**2.17**	(1.93)	212%	**0.34**	(0.79)	143%
Operating netback after financial derivatives gain (loss)	**$ 29.86**	$ 36.76	(19%)	**$ 31.68**	$ 33.78	(6%)

(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 derivatives reflect realized gains (losses) only.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2012**	2011	Change	**2012**	2011	Change
General and administrative expenses	**$ 11,137**	$ 8,689	28%	**$ 22,325**	$ 19,819	13%
General and administrative expenses per boe	**$. 2.31**	$ 2.00	16%	**$ 2.30**	$ 2.30	–%

General and administrative expenses for the second quarter of 2012 increased to $11.1 million from $8.7 million, as compared to the same period in 2011. On a per boe basis, general and administrative expenses increased by 16% from $2.00 in the second quarter of 2011 to $2.31 in the second quarter of 2012 due to higher salary levels, higher office rent and higher costs related to the 2011 year end reserve report.

General and administrative expenses for the six months ended June 30, 2012 increased to $22.3 million from $19.8 million, as compared to the same period in 2011. On a per boe basis, general and administrative expenses of $2.30 in the second quarter of 2012 were unchanged from the same period in 2011.

Share-based Compensation Expense

On January 1, 2011, the Company adopted a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards may be granted to directors, officers and employees of the Company and its subsidiaries. Concurrent with the adoption of the Share Award Incentive Plan, no further grants were made under the Common Share Rights Incentive Plan (the "Share Rights Plan).

Compensation expense related to the Share Rights Plan decreased to $0.7 million in the second quarter of 2012 (three months ended June 30, 2011 – $4.5 million) while compensation expense related to the Share Award Incentive Plan increased to $11.6 million for the three months ended June 30, 2012 (three months ended June 30, 2011 – $2.9 million). The overall increase in compensation expense of $5.0 million is mainly due to the conversion of restricted awards and performance awards held by a departed executive.

Compensation expense related to the Share Rights Plan decreased to $1.2 million in the six months ended June 30, 2012 (six months ended June 30, 2011 – $9.8 million) while compensation expense related to the Share Award Incentive Plan increased to $18.0 million for the six months ended June 30, 2012 (six months ended June 30, 2011 – $5.6 million). The overall increase in compensation expense of $3.9 million is mainly due to the conversion of restricted awards and performance awards held by a departed executive.

Compensation expense associated with the Share Rights Plan and the Share Award Incentive Plan is recognized in income over the vesting period of the share rights or share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the exercise of share rights or conversion of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Financing Costs

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for %)	**2012**	2011	Change	**2012**	2011	Change
Bank loan and other	**$ 3,144**	$ 3,086	2%	**$ 5,684**	$ 6,807	(16%)
Long-term debt	**6,168**	6,008	3%	**12,281**	10,704	15%
Accretion on asset retirement obligations	**1,652**	1,516	9%	**3,279**	3,000	9%
Debt financing costs	**830**	2,183	(62%)	**849**	2,844	(70%)
Financing costs	**$ 11,794**	$ 12,793	(8%)	**$ 22,093**	$ 23,355	(5%)

Financing costs for the three months ended June 30, 2012 decreased to $11.8 million, as compared to $12.8 million in the second quarter of 2011. The decrease was primarily attributable to lower credit facility amendment fees and lower average borrowing on bank loans coupled with lower interest rates, offset by interest on the US$150 million principal amount of 6.75% Series B senior unsecured debentures issued on February 17, 2011.

Financing costs for the six months ended June 30, 2012 decreased to $22.1 million, as compared to $23.4 million in the first half of 2011. The decrease was primarily attributable to lower credit facility amendment fees and lower average borrowing on bank loans coupled with lower interest rates, offset by interest on the US$150 million principal amount of 6.75% Series B senior unsecured debentures issued on February 17, 2011.

Foreign Exchange

($ thousands except for % and exchange rates)	Three Months Ended June 30			Six Months Ended June 30		
	2012	2011	Change	**2012**	2011	Change
Unrealized foreign exchange (gain) loss	**$ 8,105**	$ (4,746)	(271%)	**$ 2,112**	$ (9,602)	(122%)
Realized foreign exchange loss (gain)	**(1,225)**	740	266%	**(100)**	1,666	106%
Total (gain) loss	**$ 6,880**	$ (4,006)	(271%)	**$ 2,012**	$ (7,936)	(125%)
CAD/USD exchange rates:						
At beginning of period	**0.9991**	0.9718		**1.0170**	0.9946	
At end of period	**1.0191**	0.9643		**1.0191**	0.9643	

The foreign exchange loss for the three months ended June 30, 2012 was $6.9 million and comprised of an unrealized foreign exchange loss of $8.1 million and a realized foreign exchange gain of $1.2 million. The foreign exchange gain for the three months ended June 30, 2011 was $4.0 million and comprised of an unrealized foreign exchange gain of $4.7 million and a realized foreign exchange loss of $0.7 million. The second quarter of 2012 unrealized loss of $8.1 million, as compared to a gain of $4.7 million for the second quarter of 2011, was mainly due to the translation of the US$180 million portion of the bank loan and US$150 million Series B senior unsecured debentures as the Canadian dollar weakened against the U.S. dollar at June 30, 2012 (as compared to March 31, 2012) and strengthened at June 30, 2011 (as compared to March 31, 2011). The current quarter realized gains were due to day-to-day U.S. dollar denominated transactions.

The foreign exchange loss for the six months ended June 30, 2012 was $2.0 million and comprised of an unrealized foreign exchange loss of $2.1 million and a realized foreign exchange gain of $0.1 million. The foreign exchange gain for the six months ended June 30, 2011 was $7.9 million and comprised of an unrealized foreign exchange gain of $9.6 million and a realized foreign exchange loss of $1.7 million. The unrealized loss in the first half of 2012 of $2.1 million, as compared to a gain of $9.6 million for the first half of 2011, was mainly due to the translation of the US$180 million portion of the bank loan and US$150 million Series B senior unsecured debentures as the Canadian dollar weakened against the U.S. dollar at June 30, 2012 (as compared to December 31, 2011) and strengthened at June 30, 2011 (as compared to December 31, 2010). The current quarter realized gains were due to day-to-day U.S. dollar denominated transactions.

Depletion and Depreciation

Depletion and depreciation for the three months ended June 30, 2012 increased to $70.6 million from $56.4 million for the same period in 2011. On a sales-unit basis, the provision for the current quarter was $14.64 per boe, as compared to $12.32 per boe for the same quarter in 2011. The increase relates primarily to an increase in estimates of future development costs resulting in a higher depletable base.

Depletion and depreciation for the six months ended June 30, 2012 increased to $142.9 million from $113.1 million for the same period in 2011. On a sales-unit basis, the provision for the first half of 2012 was $14.74 per boe, as compared to $12.79 per boe for the same period in 2011. The increase relates primarily to an increase in estimates of future development costs resulting in a higher depletable base.

Income Taxes

For the six months ended June 30, 2012, total income tax expense was $110.0 million (six months ended June 30, 2011 – $16.0 million) of which $16.7 million related to current income taxes (six months ended June 30, 2011 – $nil) and $93.4 million related to deferred income taxes (six months ended June 30, 2011 – $16.0 million). The increase in income tax expense relates primarily to the disposition of non-operated assets in North Dakota during the second quarter of 2012. The gain on disposition is, to the extent possible, sheltered from current taxes by available U.S. tax deductions. The unsheltered portion of the gain results in a $16.7 million current tax expense payable to U.S. federal and state tax authorities. The remaining increase in income tax expense relates to changes in unrealized financial derivatives gains and losses and other minor differences.

Net Income

Net income for the three months ended June 30, 2012 was $157.3 million, as compared to $106.9 million for the same period in 2011. The increase in net income was primarily the result of a $175.4 million gain on disposition of U.S. properties and increase in gain on financial derivative contracts, offset by lower operating netback, higher income tax expense and higher depletion and depreciation.

Net income for the six months ended June 30, 2012 was $200.2 million, as compared to $107.8 million for the same period in 2011. The increase in net income was primarily the result of a $175.4 million gain on disposition of U.S. properties and increase in gain on financial derivative contracts, offset by lower operating netback, higher income tax expense and higher depletion and depreciation.

Other Comprehensive Income

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities that form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

The $1.9 million balance of accumulated other comprehensive loss at June 30, 2012 is the sum of a $3.5 million foreign currency translation loss incurred as at December 31, 2011 and a $1.6 million foreign currency translation gain related to the six months ended June 30, 2012.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends (net of participation in the Dividend 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 GAAP measure) to funds from operations (a non-GAAP measure):

	Three Months Ended			Six Months Ended	
($ thousands except for %)	**June 30, 2012**	March 31, 2012	June 30, 2011	**June 30, 2012**	June 30, 2011
Cash flow from operating activities	**$ 122,701**	$ 151,361	$ 146,199	**$ 274,062**	$ 266,098
Change in non-cash working capital	**11,594**	(1,881)	2,206	**9,713**	(186)
Asset retirement expenditures	**377**	771	959	**1,148**	1,878
Financing costs	**(11,794)**	(10,299)	(12,793)	**(22,093)**	(23,355)
Accretion on asset retirement obligations	**1,652**	1,627	1,516	**3,279**	3,000
Accretion on debentures and long-term debt	**162**	157	146	**319**	268
Funds from operations	**$ 124,692**	$ 141,736	$ 138,233	**$ 266,428**	$ 247,703
Cash dividends declared	**$ 78,908**	$ 78,365	$ 69,425	**$ 157,273**	$ 104,765
Reinvested dividends	**26,965**	22,806	16,661	**49,771**	33,453
Cash dividends declared (net of DRIP)	**$ 51,943**	$ 55,559	$ 52,764	**$ 107,502**	$ 71,312
Payout ratio	**63%**	55%	50%	**59%**	42%
Payout ratio (net of DRIP)	**42%**	39%	38%	**40%**	29%

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 dividends declared, net of DRIP participation, of $51.9 million for the second quarter of 2012 were funded through funds from operations of $124.7 million. Cash dividends declared, net of DRIP participation, of $107.5 million for the six month ended June 30, 2012 were funded through funds from operations of $266.4 million.

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)	June 30, 2012	December 31, 2011
Bank loan	$ 396,207	$ 311,960
Long-term debt[1]	302,865	302,550
Working capital (surplus) deficiency	(261,153)	36,071
Total monetary debt	$ 437,919	$ 650,581

(1) Principal amount of instruments.

At June 30, 2012, total monetary debt was $437.9 million, as compared to $650.6 million at December 31, 2011. Bank borrowings at June 30, 2012 were $396.2 million, as compared to total credit facilities of $700 million.

Our wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40 million extendible operating loan facility with a chartered bank and a $660 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time). On June 12, 2012, the maturity date of the credit facilities was extended by one year to June 14, 2015. The Credit Facilities contain standard commercial covenants for facilities of this nature. Baytex Energy is in compliance with all such covenants. The credit facilities do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement (and related amendments) which establishes the credit facilities and related amendments are accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011 and July 10, 2012).

The weighted average interest rate on the bank loan for six months ended June 30, 2012 was 3.50% (3.69% for year ended December 31, 2011 and 3.88% for the six months ended June 30, 2011).

On February 17, 2011, we issued US$150 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 Baytex Energy's credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

On July 19, 2012, we issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. The net proceeds from the issuance were advanced to Baytex Energy which used the funds to repay a portion of the amount drawn on its credit facilities.

Also on July 19, 2012, we called our 9.15% Series A senior unsecured debentures due August 26, 2016 ($150 million principal amount) for redemption on August 26, 2012 at 104.575% of the principal amount. The payment of the redemption price will be funded by drawing upon Baytex Energy's credit facilities.

Pursuant to various agreements with our lenders, we are restricted from paying 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 our senior unsecured debentures and Baytex Energy's 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:

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	2012	2011	2012	2011
Land	$ 4,195	$ 2,326	$ 6,787	$ 4,551
Seismic	694	45	1,542	168
Drilling and completion	69,256	73,744	164,591	136,939
Equipment	28,831	32,341	65,886	53,772
Other	(81)	(3)	7	37
Total exploration and development	$ 102,895	$ 108,453	$ 238,813	$ 195,467
Acquisitions – Corporate	–	1,325	–	118,671
Acquisitions – Properties	10,173	(185)	12,509	37,333
Proceeds from divestitures	(313,834)	–	(317,402)	–
Total acquisitions and divestitures	(303,661)	1,140	(304,893)	156,004
Total oil and natural gas expenditures	(200,766)	109,593	(66,080)	351,471
Other plant and equipment, net	1,623	1,100	6,667	825
Total capital expenditures	$ (199,143)	$ 110,693	$ (59,413)	$ 352,296

On May 22, 2012, Baytex Energy USA Ltd. ("Baytex USA"), an indirect, wholly-owned subsidiary, disposed of its non-operated interests in North Dakota, which consisted of $116.8 million of oil and gas properties and $21.6 million of exploration and evaluation assets, for net cash proceeds of $313.8 million. Gains totaling $175.4 million were recognized in the statements of income and comprehensive income.

The net cash proceeds from the disposition were deposited into an escrow account in accordance with Section 1031 of the United States Internal Revenue Code, which provides the ability to defer in whole or in part the payment of federal income taxes on a gain on disposition in the event that the sale proceeds are redeployed into a replacement property which is indentified within 45 days of closing of the disposition and ultimately acquired within 180 days of the closing of the disposition. As at June 30, 2012, US$312.0 million was held in the escrow account. On July 16, 2012, US$112.5 million of the escrowed funds were returned to Baytex USA from the escrow account. In the event that a replacement property is not acquired by November 18, 2012, the remaining escrowed funds will be returned to Baytex USA.

Shareholders' Capital

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 August 10, 2012, the Company had 120,284,524 common shares and no preferred shares issued and outstanding.

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 on an ongoing manner. A significant portion of these obligations will be funded with funds from operations. These obligations as of June 30, 2012, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 215,666	$ 215,666	$ –	$ –	$ –
Dividends payable to shareholders	26,381	26,381	–	–	–
Bank loan[1]	396,207	–	396,207	–	–
Long-term debt[2]	302,865	–	–	150,000	152,865
Operating leases	48,488	5,887	12,419	12,432	17,750
Processing agreements	70,001	4,037	10,989	11,300	43,675
Transportation agreements	68,238	1,546	9,324	17,254	40,114
Total	$1,127,846	$ 253,517	$ 428,939	$ 190,986	$ 254,404

(1) The bank loan is a covenant-based revolving loan that is extendible annually for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2015 with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex is exposed to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is managed by Baytex through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Baytex manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

A summary of the risk management contracts in place as at June 30, 2012 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2012		2011				2010	
($ thousands, except per common share or trust unit amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Gross revenues	284,248	343,355	367,813	313,787	336,899	290,315	263,497	238,276
Net income	157,280	42,958	57,780	51,839	106,863	950	21,356	23,319
Per common share or trust unit – basic	1.32	0.36	0.49	0.45	0.92	0.01	0.19	0.21
Per common share or trust unit – diluted	1.30	0.36	0.48	0.44	0.90	0.01	0.18	0.20

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 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; and the existence, operation and strategy of our risk management program. 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. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

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 receipt, in a timely manner, of regulatory and other required approvals; 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 natural gas operations; changes in royalty rates and incentive programs relating to the oil and natural gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; failure to obtain the necessary regulatory and other approvals on the planned timelines 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, 2011, 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.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	June 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash	$ 312,466	$ 7,847
Trade and other receivables	189,997	206,951
Crude oil inventory	737	898
Financial derivatives (note 15)	33,858	10,879
	537,058	226,575
Non-current assets		
Deferred income tax asset	–	10,133
Financial derivatives (note 15)	427	180
Exploration and evaluation assets (note 3)	114,213	129,774
Oil and gas properties (note 4)	2,013,228	2,032,160
Other plant and equipment	30,321	25,233
Goodwill	37,755	37,755
	$ 2,733,002	$ 2,461,810
LIABILITIES		
Current liabilities		
Trade and other payables	$ 215,666	$ 225,831
Dividends payable to shareholders	26,381	25,936
Financial derivatives (note 15)	8,499	25,205
	250,546	276,972
Non-current liabilities		
Bank loan (note 5)	396,207	311,960
Long-term debt (note 6)	298,362	297,731
Asset retirement obligations (note 7)	265,922	260,411
Deferred income tax liability	176,011	93,217
Financial derivatives (note 15)	12,949	14,785
	1,399,997	1,255,076
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 8)	1,778,235	1,680,184
Contributed surplus	69,403	85,716
Accumulated other comprehensive loss	(1,978)	(3,546)
Deficit	(512,655)	(555,620)
	1,333,005	1,206,734
	$ 2,733,002	$ 2,461,810

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Revenues, net of royalties (note 12)	$ 238,228	$ 285,740	$ 528,589	$ 527,253
Expenses				
Exploration and evaluation	4,467	3,351	6,930	6,817
Production and operating	56,967	50,189	115,254	97,665
Transportation and blending	47,790	67,518	109,527	131,678
General and administrative	11,137	8,689	22,325	19,819
Share-based compensation (note 9)	12,345	7,354	19,201	15,336
Financing costs (note 13)	11,794	12,793	22,093	23,355
(Gain) loss on financial derivatives (note 15)	(57,864)	(41,225)	(46,522)	3,658
Foreign exchange loss (gain) (note 14)	6,880	(4,006)	2,012	(7,936)
Gain on divestiture of oil and gas properties (note 4)	(175,406)	–	(175,406)	–
Depletion and depreciation	70,581	56,469	142,892	113,113
	(11,309)	161,132	218,306	403,505
Net income before income taxes	249,537	124,608	310,283	123,748
Income tax expense (note 11)				
Current income tax expense	16,664	–	16,664	–
Deferred income tax expense	75,593	17,745	93,381	15,935
	92,257	17,745	110,045	15,935
Net income attributable to shareholders	$ 157,280	$ 106,863	$ 200,238	$ 107,813
Other comprehensive income (loss)				
Foreign currency translation adjustment	6,954	(1,650)	1,568	(6,648)
Comprehensive income	$ 164,234	$ 105,213	$ 201,806	$ 101,165
Net income per common share (note 10)				
Basic	$ 1.32	$ 0.92	$ 1.68	$ 0.94
Diluted	$ 1.30	$ 0.90	$ 1.66	$ 0.91
Weighted average common shares (note 10)				
Basic	119,387	115,596	118,975	115,006
Diluted	120,991	118,481	120,839	118,116

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) (unaudited)	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2010	$ 1,484,335	$ 129,129	$ (10,323)	$ (492,005)	**$ 1,111,136**
Dividends to shareholders	–	–	–	(138,218)	**(138,218)**
Exercise of share rights	76,002	(47,522)	–	–	**28,480**
Share-based compensation	–	15,336	–	–	**15,336**
Issued pursuant to dividend reinvestment plan	33,738	–	–	–	**33,738**
Comprehensive income (loss) for the period	–	–	(6,648)	107,813	**101,165**
Balance at June 30, 2011	$ 1,594,075	$ 96,943	$ (16,971)	$ (522,410)	**$ 1,151,637**
Balance at December 31, 2011	$ 1,680,184	$ 85,716	$ (3,546)	$ (555,620)	**$ 1,206,734**
Dividends to shareholders	–	–	–	(157,273)	**(157,273)**
Exercise of share rights	36,492	(21,428)	–	–	**15,064**
Vesting of share awards	14,086	(14,086)	–	–	**–**
Share-based compensation	–	19,201	–	–	**19,201**
Issued pursuant to dividend reinvestment plan	47,473	–	–	–	**47,473**
Comprehensive income (loss) for the period	–	–	1,568	200,238	**201,806**
Balance at June 30, 2012	$ 1,778,235	$ 69,403	$ (1,978)	$ (512,655)	**$ 1,333,005**

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
(thousands of Canadian dollars) (unaudited)	2012	2011	2012	2011
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	$ 157,280	$ 106,863	$ 200,238	$ 107,813
Adjustments for:				
Share-based compensation (note 9)	12,345	7,354	19,201	15,336
Unrealized foreign exchange loss (gain) (note 14)	8,105	(4,746)	2,112	(9,602)
Exploration and evaluation	5,100	2,470	6,930	4,954
Depletion and depreciation	70,581	56,469	142,892	113,113
Unrealized gain on financial derivatives (note 15)	(47,384)	(49,602)	(43,182)	(3,132)
Gain on divestiture of oil and gas properties (note 4)	(175,406)	–	(175,406)	–
Current income tax expense on divestiture	16,664	–	16,664	–
Deferred income tax expense (note 11)	75,593	17,763	93,381	15,953
Financing costs (note 13)	11,794	12,793	22,093	23,355
Change in non-cash working capital (note 14)	(11,594)	(2,206)	(9,713)	186
Asset retirement obligations (note 7)	(377)	(959)	(1,148)	(1,878)
	122,701	146,199	274,062	266,098
Financing activities				
Payments of dividends	(54,004)	(51,963)	(109,355)	(104,020)
Increase in bank loan	65,718	17,830	83,860	16,753
Proceeds from issuance of long-term debt (note 6)	–	–	–	145,810
Issuance of common shares (note 8)	6,239	8,849	15,064	28,480
Interest paid	(3,676)	(5,867)	(18,228)	(16,387)
	14,277	(31,151)	(28,659)	70,636
Investing activities				
Additions to exploration and evaluation assets (note 3)	(3,963)	(1,988)	(7,694)	(7,444)
Additions to oil and gas properties	(98,932)	(106,465)	(231,119)	(188,023)
Property acquisitions	(10,173)	185	(12,509)	(37,333)
Corporate acquisitions	–	(1,325)	–	(118,671)
Proceeds from divestitures (note 4)	313,834	–	317,402	–
Current income tax expense on divestiture	(16,664)	–	(16,664)	–
Additions to other plant and equipment, net of disposals	(1,623)	(1,100)	(6,667)	(825)
Change in non-cash working capital (note 14)	(9,276)	(6,513)	16,842	17,317
	173,203	(117,206)	59,591	(334,979)
Impact of foreign currency translation on cash balances	(527)	245	(375)	304
Change in cash	309,654	(1,913)	304,619	2,059
Cash, beginning of period	2,812	3,972	7,847	–
Cash, end of period	$ 312,466	$ 2,059	$ 312,466	$ 2,059

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at June 30, 2012, December 31, 2011 *and for the three months and six months ended June 30, 2012 and 2011*
(all tabular amounts in thousands of Canadian dollars, except per common share amounts) (unaudited)

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an 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. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 - 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2011. The Company's accounting policies are unchanged compared to December 31, 2011 and the use of estimates and judgments is also consistent with the December 31, 2011 financial statements.

The consolidated financial statements were approved and authorized by the Board of Directors on August 13, 2012.

The consolidated financial statements have been prepared on the historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated.

3. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2010	**$ 113,082**
Capital expenditures	9,104
Corporate acquisition	14,944
Property acquisition	18,013
Exploration and evaluation expense	(10,130)
Transfer to oil and gas properties	(14,398)
Divestitures	(2,058)
Foreign currency translation	1,217
As at December 31, 2011	**$ 129,774**
Capital expenditures	7,694
Property acquisition	10,515
Exploration and evaluation expense	(6,930)
Transfer to oil and gas properties	(4,997)
Divestitures	(22,034)
Foreign currency translation	191
As at June 30, 2012	**$ 114,213**

4. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2010	**$ 1,819,351**
Capital expenditures	364,578
Corporate acquisition	131,635
Property acquisitions	61,137
Transferred from exploration and evaluation assets	14,398
Change in asset retirement obligations	84,879
Divestitures	(10,233)
Foreign currency translation	5,674
As at December 31, 2011	**$ 2,471,419**
Capital expenditures	231,119
Property acquisitions	1,994
Transferred from exploration and evaluation assets	4,997
Change in asset retirement obligations	3,378
Divestitures	(133,050)
Foreign currency translation	980
As at June 30, 2012	**$ 2,580,837**

Accumulated depletion	
As at December 31, 2010	**$ 194,722**
Depletion for the period	244,893
Divestitures	(667)
Foreign currency translation	311
As at December 31, 2011	**$ 439,259**
Depletion for the period	141,312
Divestitures	(13,089)
Foreign currency translation	127
As at June 30, 2012	**$ 567,609**

Carrying value	
As at December 31, 2011	**$ 2,032,160**
As at June 30, 2012	**$ 2,013,228**

On May 22, 2012, Baytex Energy USA Ltd. ("Baytex USA"), an indirect, wholly-owned subsidiary, disposed of its non-operated interests in North Dakota, which consisted of $116.8 million of oil and gas properties and $21.6 million of exploration and evaluation assets, for net cash proceeds of $313.8 million. Gains totaling $175.4 million were recognized in the statements of income and comprehensive income.

5. BANK LOAN

As at	June 30, 2012	December 31, 2011
Bank loan	**$ 396,207**	$ 311,960

Baytex Energy Ltd. ("Baytex Energy"), a wholly-owned subsidiary of Baytex, has established a $40.0 million extendible operating loan facility with a chartered bank and a $660.0 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time). On June 12, 2012, the maturity date of the credit facilities was extended by one year to June 14, 2015. The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain of its material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, Baytex's ability to pay dividends to its shareholders may be restricted.

Financing costs for the six months ended June 30, 2012 include facility amendment fees of $0.8 million ($2.2 million for the six months ended June 30, 2011). The weighted average interest rate on the bank loan for six months ended June 30, 2012 was 3.50% (3.88% for the six months ended June 30, 2011).

6. LONG-TERM DEBT

As at	June 30, 2012	December 31, 2011
9.15% senior unsecured debentures (Cdn$150,000 – principal)	$ 147,562	$ 147,328
6.75% senior unsecured debentures (US$150,000 – principal)	150,800	150,403
	$ 298,362	$ 297,731

On July 19, 2012, Baytex issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. The net proceeds from the issuance were advanced to Baytex Energy which used the funds to repay a portion of the amount drawn on its credit facilities.

Also on July 19, 2012, Baytex called its 9.15% Series A senior unsecured debentures due August 26, 2016 ($150 million principal amount) for redemption on August 26, 2012 at 104.575% of the principal amount. The payment of the redemption price will be funded by drawing upon Baytex Energy's credit facilities.

Accretion expense on debentures of $0.2 million has been recorded for the three months ended June 30, 2012 (three months ended June 30, 2011 – $0.1 million) and $0.3 million for the six months ended June 30, 2012 (six months ended June 30, 2011 – $0.3 million).

7. ASSET RETIREMENT OBLIGATIONS

	June 30, 2012	December 31, 2011
Balance, beginning of period	$ 260,411	$ 169,611
Liabilities incurred	3,502	5,834
Liabilities settled	(1,148)	(10,588)
Liabilities acquired	–	5,003
Liabilities divested	(1,457)	(556)
Accretion	3,279	6,185
Change in estimate[1]	1,333	84,879
Foreign currency translation	2	43
Balance, end of period	$ 265,922	$ 260,411

(1) Changes in the status of wells, changes in discount rates 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 the facilities using existing technology 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 undiscounted amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% at June 30, 2012 is $318.7 million (December 31, 2011 – $315.9 million). The amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% and discounted at a risk free rate of 2.5% at June 30, 2012 (December 31, 2011 – 2.5%) is $265.9 million (December 31, 2011 – $260.4 million).

8. SHAREHOLDERS' CAPITAL

Shareholders' Capital

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at June 30, 2012, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000's)*	Amount
Balance, December 31, 2010	**113,712**	**$ 1,484,335**
Issued on exercise of share rights	2,665	45,048
Transfer from contributed surplus on exercise of share rights	–	77,258
Issued pursuant to dividend reinvestment plan	1,516	73,543
Balance, December 31, 2011	**117,893**	**$ 1,680,184**
Issued on exercise of share rights	794	15,064
Transfer from contributed surplus on exercise of share rights	–	21,428
Transfer from contributed surplus on vesting of share awards	277	14,086
Issued pursuant to dividend reinvestment plan	950	47,473
Balance, June 30, 2012	**119,914**	**$ 1,778,235**

Monthly dividends of $0.22 per common share were declared by the Company during the three and six months ended June 30, 2012 for total dividends declared of $78.9 million and $157.3 million, respectively.

Subsequent to June 30, 2012, the Company announced that a monthly dividend in respect of July 2012 operations of $0.22 per common share totaling $26.3 million will be payable on August 15, 2012 to shareholders of record on July 31, 2012.

9. EQUITY BASED PLANS

Share Rights Plan

As a result of the conversion of the legal structure of Baytex Energy Trust (the "Trust") from an income trust to a corporation at year-end 2010, all outstanding rights to acquire trust units of the Trust ("unit rights") were exchanged for equivalent rights to acquire common shares of Baytex ("share rights"), which are governed by the terms of the Common Share Rights Incentive Plan (the "Share Rights Plan"). As a result of the adoption of the Share Award Incentive Plan (as described below) effective January 1, 2011, no further grants will be made under the Share Rights Plan. The Share Rights Plan will remain in place until such time as all outstanding share rights have been exercised, cancelled or expired.

Baytex recorded compensation expense related to the share rights under the Share Rights Plan of $0.7 million for the three months ended June 30, 2012 (three months ended June 30, 2011 – $4.5 million) and $1.2 million for the six months ended June 30, 2012 (six months ended June 30, 2011 – $9.8 million).

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

	Number of share rights *(000's)*	Weighted average exercise price
Balance, December 31, 2010(1)	**5,761**	**$ 17.02**
Exercised(2)	(2,665)	16.92
Forfeited(1)	(125)	23.05
Balance, December 31, 2011(1)	**2,971**	**$ 16.98**
Exercised(2)	(794)	19.04
Forfeited(1)	(78)	21.12
Balance, June 30, 2012(1)	**2,099**	**$ 16.22**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price.

(2) Weighted average exercise price includes rights exercised at both original grant prices and original grant prices reduced for dividends and distributions subsequent to grant date.

The following table summarizes information about the share rights outstanding at June 30, 2012:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Dividends and Distributions Subsequent to Grant Date				
PRICE RANGE	**Number Outstanding at June 30, 2012** *(000's)*	Weighted Average Grant Price	Weighted Average Remaining Term *(years)*	**Number Exercisable at June 30, 2012** *(000's)*	Weighted Average Exercise Price	**Number Outstanding at June 30, 2012** *(000's)*	Weighted Average Exercise Price	Weighted Average Remaining Term *(years)*	**Number Exercisable at June 30, 2012** *(000's)*	Weighted Average Exercise Price
$5.34 to $12.50	5	$ 12.46	1.7	5	$ 12.46	949	$ 9.63	1.0	949	$ 9.63
$12.51 to $19.50	663	17.97	1.3	663	17.97	221	16.87	1.7	162	17.28
$19.51 to $26.50	495	20.36	0.8	431	20.08	812	21.76	2.4	477	21.71
$26.51 to $33.50	894	27.93	2.4	532	27.90	100	29.02	2.7	48	28.40
$33.51 to $40.50	39	35.71	3.1	11	35.06	16	34.81	3.1	7	34.61
$40.51 to $47.72	3	45.02	3.4	1	45.19	1	43.95	3.5	–	43.95
$5.34 to $47.72	2,099	$ 23.12	1.7	1,643	$ 21.85	2,099	$ 16.22	1.7	1,643	$ 14.55

Share Award Incentive Plan

The Company has 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 and employees 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.

The Company recorded compensation expense related to the share awards of $11.6 million for the three months ended June 30, 2012 (three months ended June 30, 2011 – $2.9 million) and $18.0 million for the six months ended June 30, 2012 (six months ended June 30, 2011 – $5.6 million).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 4.6% of outstanding share awards. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. The estimated weighted average fair value for share awards at the measurement date is $56.04 per restricted award and performance award granted during the six months ended June 30, 2012 (six months ended June 30, 2011 – $48.76 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000's)*	Number of performance awards *(000's)*	Number of share awards *(000's)*
Balance, December 31, 2010	**–**	**–**	**–**
Granted	389	243	632
Forfeited	(24)	(14)	(38)
Balance, December 31, 2011	**365**	**229**	**594**
Granted	183	147	330
Vested and converted to common shares	(72)	(99)	(171)
Forfeited	(33)	(21)	(54)
Balance, June 30, 2012	**443**	**256**	**699**

10. NET INCOME PER SHARE

Baytex calculates basic income per share based on the net income attributable to shareholders and a weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share rights were exercised and share awards were converted. The treasury stock method is used to determine the dilutive effect of share rights and share awards whereby any proceeds from the exercise of share rights and the conversion of share awards or other dilutive instruments and the amount of compensation expense, if any, attributed to future services not yet recognized are assumed to be used to purchase common shares at the average market price during the periods.

	Three Months Ended June 30, 2012			Three Months Ended June 30, 2011		
	Net income	**Common Shares (000's)**	**Net income per share**	Net income	Common Shares (000's)	Net income per share
Net income – basic	**$157,280**	**119,387**	**$ 1.32**	$106,863	115,596	$ 0.92
Dilutive effect of share rights	**–**	**1,152**		–	2,740	
Dilutive effect of share awards	**–**	**452**		–	145	
Net income – diluted	**$157,280**	**120,991**	**$ 1.30**	$106,863	118,481	$ 0.90

For the three months ended June 30, 2012, and 2011, no share rights were anti-dilutive.

	Six Months Ended June 30, 2012			Six Months Ended June 30, 2011		
	Net income	**Common Shares (000's)**	**Net income per share**	Net income	Common Shares (000's)	Net income per share
Net income – basic	**$200,238**	**118,975**	**$ 1.68**	$107,813	115,006	$ 0.94
Dilutive effect of share rights	**–**	**1,325**		–	2,987	
Dilutive effect of share awards	**–**	**539**		–	123	
Net income – diluted	**$200,238**	**120,839**	**$ 1.66**	$107,813	118,116	$ 0.91

For the six months ended June 30, 2012, and 2011, no share rights were anti-dilutive.

11. INCOME TAXES

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

	Six months ended June 30	
	2012	2011
Net income before income taxes	$ 310,283	$ 123,748
Expected income taxes at the statutory rate of 25.45% (2011 – 26.97%)(1)	78,967	33,375
Increase (decrease) in income taxes resulting from:		
Non-taxable portion of foreign exchange loss (gain)	88	(1,191)
Share-based compensation	4,886	4,137
Effect of change in income tax rates	(243)	(6,749)
Effect of rate adjustments for foreign jurisdictions	22,573	(1,672)
Effect of change in opening tax pool balances	–	(10,395)
Other	3,774	(1,570)
Income tax expense	$ 110,045	$ 15,935

(1) The change in statutory rate is related to a legislated reduction in the Canadian federal corporate income tax rate and changes in the provincial apportionment of income.

12. REVENUES

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Petroleum and natural gas revenues	$ 284,632	$ 335,811	$ 625,787	$ 625,603
Royalty charges	(46,020)	(51,159)	(99,014)	(99,961)
Royalty income	(384)	1,088	1,816	1,611
Revenues, net of royalties	$ 238,228	$ 285,740	$ 528,589	$ 527,253

13. FINANCING COSTS

Baytex incurred financing costs on its outstanding liabilities as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Bank loan and other	$ 3,144	$ 3,086	$ 5,684	$ 6,807
Long-term debt	6,168	6,008	12,281	10,704
Accretion on asset retirement obligations	1,652	1,516	3,279	3,000
Debt financing costs	830	2,183	849	2,844
Financing costs	$ 11,794	$ 12,793	$ 22,093	$ 23,355

14. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Trade and other receivables	$ (9,407)	$ (12,484)	$ 16,954	$ (39,951)
Crude oil inventory	(169)	–	161	1,802
Trade and other payables	(12,447)	4,590	(10,432)	56,208
Foreign exchange	1,153	(825)	446	(556)
	$ (20,870)	$ (8,719)	$ 7,129	$ 17,503
Changes in non-cash working capital related to:				
Operating activities	$ (11,594)	$ (2,206)	$ (9,713)	$ 186
Investing activities	(9,276)	(6,513)	16,842	17,317
	$ (20,870)	$ (8,719)	$ 7,129	$ 17,503

Foreign Exchange

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Unrealized foreign exchange loss (gain)	$ 8,105	$ (4,746)	$ 2,112	$ (9,602)
Realized foreign exchange (gain) loss	(1,225)	740	(100)	1,666
Foreign exchange loss (gain)	$ 6,880	$ (4,006)	$ 2,012	$ (7,936)

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, dividends payable to shareholders, bank loan, financial derivatives and long-term debt.

Categories of Financial Instruments

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 and long-term debt, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term debt is based on the trading value of the debentures.

Fair Value of Financial Instruments

Baytex classifies the fair value of 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 carried on the condensed consolidated statements of financial position are classified into the following categories:

	June 30, 2012		December 31, 2011		
As at	Carrying Value	Fair Value	Carrying Value	Fair Value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[(1)]					
Cash	$ 312,466	$ 312,466	$ 7,847	$ 7,847	Level 1
Derivatives	34,285	34,285	11,059	11,059	Level 2
Total FVTPL[(1)]	$ 346,751	$ 346,751	$ 18,906	$ 18,906	
Loans and receivables					
Trade and other receivables	$ 189,997	$ 189,997	$ 206,951	$ 206,951	–
Total loans and receivables	$ 189,997	$ 189,997	$ 206,951	$ 206,951	
Financial Liabilities					
FVTPL[(1)]					
Derivatives	$ (21,448)	$ (21,448)	$ (39,990)	$ (39,990)	Level 2
Total FVTPL[(1)]	$ (21,448)	$ (21,448)	$ (39,990)	$ (39,990)	
Other financial liabilities					
Trade and other payables	$ (215,666)	$ (215,666)	$ (225,831)	$ (225,831)	–
Dividends payable to shareholders	(26,381)	(26,381)	(25,936)	(25,936)	–
Bank loan	(396,207)	(396,207)	(311,960)	(311,960)	–
Long-term debt	(298,362)	(315,290)	(297,731)	(314,201)	–
Total other financial liabilities	$ (936,616)	$ (953,544)	$ (861,458)	$ (877,928)	

(1) FVTPL means fair value through profit or loss.

There were no transfers between Level 1 and 2 in the period.

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, its Series B senior unsecured debentures, 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 – U.S. exchange rate.

At June 30, 2012, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	January 2011 to August 2012	US$1.00 million	1.0565	(1)
Monthly forward spot sale	January 2011 to September 2012	US$1.50 million	1.0553	(1)
Monthly forward spot sale	November 2011 to October 2013	US$1.00 million	1.0433	(1)
Monthly average rate forward	Calendar 2012	US$1.25 million	1.0209	(2)
Monthly spot collar	Calendar 2012	US$0.75 million	0.9524 - 1.0503	(1)
Monthly spot collar	Calendar 2012	US$0.25 million	1.0200 - 1.0700	(1)
Monthly average collar	Calendar 2012	US$0.25 million	0.9700 - 1.0310	(1)
Monthly average collar	Calendar 2012	US$0.50 million	0.9750 - 1.0305	(1)
Monthly average collar	Calendar 2012	US$0.50 million	0.9900 - 1.0805	(2)
Monthly average collar	Calendar 2012	US$0.75 million	1.0225 - 1.0425	(1)
Monthly average collar	Calendar 2012	US$0.25 million	1.0295 - 1.0545	(1)
Monthly forward spot sale	Calendar 2013	US$4.50 million	1.0007	(2)
Monthly average rate forward	Calendar 2013	US$0.25 million	1.0023	(1)
Monthly average collar	Calendar 2013	US$0.25 million	0.9700 - 1.0310	(1)
Monthly spot collar	Calendar 2012	US$1.00 million	0.9800 - 1.0722	(1)
Monthly spot collar	Calendar 2012	US$1.00 million	0.9900 - 1.0720	(1)
Monthly spot collar	Calendar 2012	US$0.50 million	0.9900 - 1.0785	(1)
Monthly forward spot sale	April 2012 to December 2012	US$3.00 million	0.9963	(1)
Monthly spot collar	June 2012 to December 2012	US$1.00 million	0.9800 - 1.0720	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0000 - 1.0725	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0100 - 1.0720	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0200 - 1.0575	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0200 - 1.0655	(1)
Monthly average collar	June 2012 to December 2013	US$1.00 million	1.0250 - 1.0702	(1)
Monthly average collar	June 2012 to December 2013	US$2.00 million	1.0300 - 1.0650	(1)
Monthly forward spot sale	July 2012 to December 2012	US$2.50 million	1.0173	(2)

(1) Actual contract rate (CAD/USD).
(2) Based on the weighted average contract rates (CAD/USD).

The following table demonstrates the effect of exchange rate movements on net income due to changes in the fair value of risk management contracts in place at June 30, 2012 as well as the unrealized gain or loss on revaluation of outstanding U.S. dollar denominated debt. The sensitivity is based on a $0.01 increase and decrease in the CAD/USD foreign exchange rate and excludes the impact on revenue proceeds.

Sensitivity of Foreign Exchange Exposure:	$0.01 Increase in CAD/USD Exchange rate	$0.01 Decrease in CAD/USD Exchange Rate
Loss (gain) on currency derivative contracts	$ 2,353	$ (2,415)
Loss (gain) on other monetary assets/liabilities	(575)	575
Net income decrease (increase)	$ 1,778	$ (1,840)

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

	Assets		Liabilities	
	June 30, 2012	December 31, 2011	**June 30, 2012**	December 31, 2011
U.S. dollar denominated	**US$461,292**	US$107,138	**US$403,952**	US$402,979

Interest Rate Risk

The Company's interest rate risk arises from Baytex Energy's floating rate bank credit facilities. As at June 30, 2012, $396.2 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 six months ended June 30, 2012 by approximately $1.4 million. Baytex uses a combination of short-term and long-term debt to finance operations. The bank loan is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

As at June 30, 2012, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
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 June 30, 2012, an increase of 100 basis points would increase the unrealized gain at June 30, 2012 by $3.7 million, while a decrease of 100 basis points would decrease the unrealized gain at June 30, 2012 by $2.0 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 June 30, 2012, a 10% increase in oil prices would decrease the unrealized gain at June 30, 2012 by $18.1 million, while a 10% decrease would increase the unrealized gain at June 30, 2012 by $17.5 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at June 30, 2012, a 10% increase in natural gas prices would decrease the unrealized gain at June 30, 2012 by $0.8 million, while a 10% decrease would increase the unrealized gain at June 30, 2012 by $0.8 million.

Financial Derivative Contracts

At June 30, 2012, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Time spread	January to December 2012	500 bbl/d	Dec 2014 plus US$3.25	WTI
Time spread	January to December 2012	500 bbl/d	Dec 2014 plus US$0.65	WTI
Price collar	March to December 2012	200 bbl/d	US$97.00 – US$117.60	WTI
Price collar	March to December 2012	300 bbl/d	US$97.00 – US$116.60	WTI
Fixed – Sell	July to September 2012	300 bbl/d	US$107.38	WTI
Fixed – Sell	July to December 2012	10,950 bbl/d	US$97.82	WTI
Price collar	Calendar 2012	400 bbl/d	US$98.00 – US$104.52	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 – US$104.90	WTI
Price collar	Calendar 2012	200 bbl/d	US$97.50 – US$104.25	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 – US$105.92	WTI
Fixed – Buy	Calendar 2012	200 bbl/d	US$102.50	WTI
Fixed – Buy	January to June 2013	250 bbl/d	US$102.07	WTI
Fixed – Buy	July to December 2013	350 bbl/d	US$101.70	WTI
Fixed – Buy	Calendar 2014	380 bbl/d	US$101.06	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.328	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.390	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.370	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.450	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.430	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.410	AECO
Basis swap	Calendar 2012	1,500 mmBtu/d	NYMEX less US$0.490	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.515	AECO
Basis swap	Calendar 2012	2,000 mmBtu/d	NYMEX less US$0.520	AECO
Basis swap	Calendar 2012	2,500 mmBtu/d	NYMEX less US$0.530	AECO
Sold call	Calendar 2012	6,000 mmBtu/d	US$5.25	NYMEX
Fixed – Sell	July to December 2012	13,000 mmBtu/d	US$4.04	NYMEX

(1) Based on the weighted average price/unit for the remainder of the contract.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	**2012**	2011
Realized (gain) loss on financial derivatives	**$ (10,480)**	$ 8,377	**$ (3,340)**	$ 6,790
Unrealized gain on financial derivatives	**(47,384)**	(49,602)	**(43,182)**	(3,132)
(Gain) loss on financial derivatives	**$ (57,864)**	$ (41,225)	**$ (46,522)**	$ 3,658

Subsequent to June 30, 2012, Baytex added the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	August to December 2012[2]	1,000 bbl/d	US$92.52	WTI
Fixed – Sell	Calendar 2013	1,500 bbl/d	US$96.00	WTI
Fixed – Sell	Calendar 2013[2]	1,000 bbl/d	US$98.00	WTI
Fixed – Sell	Calendar 2013[2]	1,000 bbl/d	US$96.10	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to increase the volumes on the contract to 2,000 bbl/d.

Physical Delivery Contracts

At June 30, 2012, 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 are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Weighted Average Price/Unit[1]
WCS Blend	October 2011 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	July to September 2012	500 bbl/d	WTI less US$15.00
WCS Blend	October to December 2012	500 bbl/d	WTI less US$18.00
WCS Blend	Calendar 2012	4,000 bbl/d	WTI less US$18.13
WCS Blend	January to June 2013	1,250 bbl/d	WTI × 80.00%
WCS Blend	January to June 2013	4,250 bbl/d	WTI less US$18.18
WCS Blend	July to December 2013	2,750 bbl/d	WTI × 80.00%
WCS Blend	July to December 2013	2,750 bbl/d	WTI less US$21.00
WCS Blend	April to December 2012	2,600 bbl/d	WTI less US$18.00
WCS Blend	June 2012 to March 2013	2,600 bbl/d	WTI less US$18.00
WCS Blend	June to December 2012	1,000 bbl/d	WTI less US$18.15
WCS Blend	January 2013 to June 2014	3,000 bbl/d	WTI less US$18.00

(1) Based on the weighted average price/unit for the remainder of the contract.

Condensate (diluent)	Period	Volume	Price/Unit
Fixed – Buy	April 2012 to March 2013	640 bbl/d	WTI plus US$6.70
Fixed – Buy	April 2012 to December 2012	120 bbl/d	WTI plus US$5.61
Fixed – Buy	June 2012 to March 2013	120 bbl/d	WTI plus US$8.00
Fixed – Buy	January 2013 to December 2013	160 bbl/d	WTI plus US$3.00

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 June 30, 2012, Baytex had available unused bank credit facilities in the amount of $303.0 million.

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

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 215,666**	$ 215,666	$ –	$ –	$ –
Dividends payable to shareholders	**26,381**	26,381	–	–	–
Bank loan(1)	**396,207**	–	396,207	–	–
Long-term debt(2)	**302,865**	–	–	150,000	152,865
	$ 941,119	$ 242,047	$ 396,207	$ 150,000	$ 152,865

(1) The bank loan is a covenant-based revolving loan that is extendible annually, for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2015 with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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 trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit and/or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers that all financial assets that are not impaired or past due for each of the reporting dates under review are of good credit quality. None of the Company's financial assets are secured by collateral.

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.

16. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

On August 4, 2011, Baytex filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $500 million (Canadian).

On July 22, 2012, Baytex issued $300 million in 10 year Series C senior unsecured debentures at par bearing a coupon rate of 6.625%. The offering was made by way of a prospectus supplement dated July 10, 2012 to Baytex's Short Form Base Prospectus dated August 4, 2011.

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect wholly-owned material subsidiaries (the "Guarantor Subsidiaries"). The guarantees of the Guarantor Subsidiaries are full and unconditional and joint and several. These guarantees may in turn be guaranteed by Baytex. Other than investments in its subsidiaries, Baytex has no independent assets or operations.

Pursuant to the credit agreement governing Baytex Energy's credit facilities, Baytex Energy and its subsidiaries are prohibited from paying dividends to their shareholders that would have, or would reasonably be expected to have, a material adverse effect or would adversely affect or impair the ability or capacity of Baytex Energy to pay or fulfill any of its obligations under the credit agreement. In addition, Baytex Energy may not permit any of its subsidiaries to pay any dividends during the continuance of a default or event of default under the credit agreement.

The following tables present condensed interim unaudited consolidating financial information as at June 30, 2012, and December 31, 2011 and for the three months and six months ended June 30, 2012 and 2011 for: 1) Baytex, on a stand-alone basis, 2) Guarantor subsidiaries, on a stand-alone basis, 3) non-guarantor subsidiaries, on a stand-alone basis and 4) Baytex, on a consolidated basis.

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
As at June 30, 2012					
Current assets	$ –	$ 536,897	$ 161	$ –	$ 537,058
Intercompany advances and investments	1,693,808	(465,524)	77,294	(1,305,578)	–
Non-current assets	2,435	2,193,509	–	–	2,195,944
Current liabilities	34,955	215,483	108	–	250,546
Bank loan and long-term debt	298,362	396,207	–	–	694,569
Asset retirement obligation and other non-current liabilities	$ –	$ 454,882	$ –	$ –	$ 454,882
As at December 31, 2011					
Current assets	$ 351	$ 225,850	$ 374	$ –	$ 226,575
Intercompany advances and investments	1,753,047	(515,492)	72,787	(1,310,342)	–
Non-current assets	2,435	2,232,800	–	–	2,235,235
Current liabilities	34,502	242,303	167	–	276,972
Bank loan and long-term debt	297,731	311,960	–	–	609,691
Asset retirement obligation and other non-current liabilities	$ –	$ 368,413	$ –	$ –	$ 368,413
For the six months ended June 30, 2012					
Revenues, net of royalties	$ 11,708	$ 529,215	$ 8,324	$ (20,658)	$ 528,589
Production, operation and exploration	–	122,184	–	–	122,184
Transportation and blending	–	109,527	–	–	109,527
General, administrative and share-based compensation	626	41,400	126	(626)	41,526
Financing, derivatives, foreign exchange and other gains/losses	12,533	(190,327)	3	(20,032)	(197,823)
Depletion and depreciation	–	142,892	–	–	142,892
Income tax expense	–	110,045	–	–	110,045
Net income (loss)	$ (1,451)	$ 193,494	$ 8,195	$ –	$ 200,238

(thousands of Canadian dollars)		Baytex		Guarantor Subsidiaries		Non-guarantor Subsidiaries		Consolidation Adjustments		Total Consolidated
For the three months ended June 30, 2012										
Revenues, net of royalties	$	5,875	$	238,479	$	4,418	$	(10,544)	$	238,228
Production, operation and exploration		–		61,434		–		–		61,434
Transportation and blending		–		47,790		–		–		47,790
General, administrative and unit-based compensation		251		23,454		28		(251)		23,482
Financing, derivatives, foreign exchange and other gains/losses		9,155		(213,458)		–		(10,293)		(214,596)
Depletion and depreciation		–		70,581		–		–		70,581
Income tax expense		–		92,257		–		–		92,257
Net income (loss)	$	(3,531)	$	156,421	$	4,390	$	–	$	157,280
For the six months ended June 30, 2011										
Revenues, net of royalties	$	10,181	$	527,253	$	3,733	$	(13,914)	$	527,253
Production, operation and exploration		–		104,482		–		–		104,482
Transportation and blending		–		131,678		–		–		131,678
General, administrative and share-based compensation		769		35,020		116		(750)		35,155
Financing, derivatives, foreign exchange and other gains/losses		7,373		24,906		(38)		(13,164)		19,077
Depletion and depreciation		–		113,113		–		–		113,113
Income tax expense		64		15,871		–		–		15,935
Net income (loss)	$	1,975	$	102,183	$	3,655	$	–	$	107,813
For the three months ended June 30, 2011										
Revenues, net of royalties	$	5,749	$	285,740	$	1,917	$	(7,667)	$	285,740
Production, operation and exploration		–		53,540		–		–		53,540
Transportation and blending		–		67,518		–		–		67,518
General, administrative and unit-based compensation		374		15,991		53		(375)		16,043
Financing, derivatives, foreign exchange and other gains/losses		2,677		(27,823)		–		(7,292)		(32,438)
Depletion and depreciation		–		56,469		–		–		56,469
Income tax expense		64		17,681		–		–		17,745
Net income (loss)	$	2,634	$	102,364	$	1,865	$	–	$	106,863

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the six months ended June 30, 2012					
Cash provided by (used in):					
Operating activities	$ 11,396	$ 251,897	$ 10,769	$ –	$ 274,062
Payment of dividends	(109,355)	–	–	–	(109,355)
Increase in bank loan	–	83,860	–	–	83,860
Increase (decrease) in intercompany loans	94,753	(21,108)	(73,645)	–	–
Increase in investments		(73,645)		73,645	–
Increase in equity	15,064	–	73,645	(73,645)	15,064
Interest paid	(11,858)	4,399	(10,769)	–	(18,228)
Financing activities	(11,396)	(6,494)	(10,769)	–	(28,659)
Additions to exploration and evaluation assets	–	(7,694)	–	–	(7,694)
Additions to oil and gas properties	–	(231,119)	–	–	(231,119)
Property acquisitions	–	(12,509)	–	–	(12,509)
Proceeds from divestitures	–	317,402	–	–	317,402
Current income tax expense on divestiture	–	(16,664)	–	–	(16,664)
Additions to other plant and equipment, net of disposals	–	(6,667)	–	–	(6,667)
Change in non-cash working capital	–	16,842	–	–	16,842
Investing activities	–	59,591	–	–	59,591
Impact of foreign currency translation on cash balances	$ –	$ (375)	$ –	$ –	$ (375)

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the six months ended June 30, 2011					
Cash provided by (used in):					
Operating activities	$ 9,240	$ 253,471	$ 3,387	$ –	$ 266,098
Payment of dividends	(104,020)	–	–	–	(104,020)
Increase in bank loan	–	16,753	–	–	16,753
Increase (decrease) in intercompany loans	(72,647)	109,030	(36,383)	–	–
Increase in investments	145,810	–	–	–	145,810
Proceeds from issuance of long-term debt		(32,996)		32,996	–
Increase in equity	28,480	–	32,996	(32,996)	28,480
Interest paid	(6,863)	(9,524)	–	–	(16,387)
Financing activities	(9,240)	83,263	(3,387)	–	70,636
Additions to exploration and evaluation assets	–	(7,444)	–	–	(7,444)
Additions to oil and gas properties	–	(188,023)	–	–	(188,023)
Property acquisitions	–	(37,333)	–	–	(37,333)
Corporate acquisitions	–	(118,671)	–	–	(118,671)
Additions to other plant and equipment, net of disposals	–	(825)	–	–	(825)
Change in non-cash working capital	–	17,317	–	–	17,317
Investing activities	–	(334,979)	–	–	(334,979)
Impact of foreign currency translation on cash balances	$ –	$ 304	$ –	$ –	$ 304

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 and
Interim Chief Executive Officer
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.

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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Alberta Treasury Branches
Bank of America
Bank of Montreal
Bank of Nova Scotia
Barclays Bank PLC
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California
Wells Fargo Bank

OFFICERS

Raymond T. Chan
Executive Chairman and
Interim Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Daniel G. Anderson
Vice President, U.S. Business Unit

Kendall D. Arthur
Vice President,
Saskatchewan Business Unit

Stephen Brownridge
Vice President, Exploration

Geoffrey J. Darcy
Vice President, Marketing

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

Brian G. Ector
Vice President, Investor Relations

Michael S. Kaluza
Vice President, Planning

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, U.S. Business Development

Richard P. Ramsay
Vice President, Heavy Oil

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