Q1 REPORT | TWO THOUSAND FOURTEEN

SUMMARY

- Generated production of 59,502 boe/d (89% oil and NGL) in Q1/2014, an increase of 2% over Q4/2013 and 15% over Q1/2013;
- Delivered funds from operations ("FFO") of $170.8 million ($1.36 per basic share) during Q1/2014, an increase of 16% over Q4/2013 and 68% over Q1/2013;
- Realized an operating netback (sales price less royalties, production and operating expenses, and transportation expenses) in Q1/2014 of $36.85/boe, an increase of 21% over Q4/2013 and 48% over Q1/2013;
- Maintained a conservative payout ratio, net of Dividend Reinvestment Plan ("DRIP") participation, of 37% (49% before DRIP) in Q1/2014;
- Ended the first quarter with total monetary debt of $832.3 million, representing a debt-to-FFO ratio of 1.2x based on FFO over the trailing twelve-month period; and
- Entered into an agreement to acquire the shares of Aurora Oil & Gas Limited ("Aurora") for total consideration of approximately $2.6 billion.

	Three Months Ended		
	March 31, 2014	December 31, 2013	March 31, 2013
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*			
Petroleum and natural gas sales	**385,809**	330,712	272,945
Funds from operations[1]	**170,810**	147,544	101,772
Per share – basic	**1.36**	1.18	0.83
Per share – diluted	**1.34**	1.17	0.82
Cash dividends declared[2]	**63,441**	59,532	56,449
Dividends declared per share	**0.66**	0.66	0.66
Net income	**47,841**	31,173	10,149
Per share – basic	**0.38**	0.26	0.08
Per share – diluted	**0.38**	0.25	0.08
Exploration and development	**172,425**	85,060	166,522
Acquisitions, net of divestitures	**673**	2,258	(42,382)
Total oil and natural gas capital expenditures	**173,098**	87,318	124,140
Bank loan	**300,564**	223,371	155,842
Long-term debt	**465,795**	459,540	452,340
Working capital deficiency	**65,909**	79,151	77,980
Total monetary debt[3]	**832,268**	762,062	686,162

	Three Months Ended		
	March 31, 2014	December 31, 2013	March 31, 2013
OPERATING			
Daily production			
Light oil and NGL (bbl/d)	**7,457**	8,047	7,920
Heavy oil (bbl/d)	**45,232**	43,254	37,486
Total oil and NGL (bbl/d)	**52,689**	51,301	45,406
Natural gas (mcf/d)	**40,886**	42,018	39,305
Oil equivalent (boe/d @ 6:1)(4)	**59,502**	58,304	51,957
Average prices (before hedging)			
WTI oil (US$/bbl)	**98.68**	97.46	94.37
WCS heavy oil (US$/bbl)	**75.55**	65.26	62.41
Edmonton par oil ($/bbl)	**100.18**	86.25	88.65
Baytex heavy oil ($/bbl)(5)	**71.13**	61.89	53.47
Baytex light oil and NGL ($/bbl)	**85.18**	74.73	76.72
Baytex total oil and NGL ($/bbl)	**73.12**	63.91	58.00
Baytex natural gas ($/mcf)	**5.22**	3.52	3.46
Baytex oil equivalent ($/boe)	**68.33**	58.75	52.89
CAD/USD noon rate at period end	**1.1053**	1.0636	1.0156
CAD/USD average rate for period	**1.1035**	1.0494	1.0089
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**45.65**	44.26	47.60
Low	**38.90**	40.21	42.00
Close	**45.52**	41.64	42.57
Volume traded (thousands)	**53,781**	22,585	27,768
NYSE			
Share price (US$)			
High	**41.28**	42.84	47.47
Low	**35.34**	37.78	41.04
Close	**41.13**	39.16	41.93
Volume traded (thousands)	**4,150**	3,657	3,369
Common shares outstanding (thousands)	**126,442**	125,392	122,874

Notes:

(1) *Funds from operations is a non-Generally Accepted Accounting Principles ("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 ended March 31, 2014.*

(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 unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan.*

(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 exclude condensate blending.*

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; the expected closing date for the Peace River - Lloydminster asset exchange; our average production rate for 2014; our exploration and development capital expenditures for 2014; our plans to comply with the recommendations from the AER's public proceeding into concerns about odours and emissions associated with heavy oil production in the Peace River area; the timing of commencing steam injection at Pad 2 of our Cliffdale cyclic steam stimulation project; the timing of first oil production from our Gemini steam-assisted gravity drainage pilot project; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; 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 the second quarter of 2014; our debt-to-FFO ratio; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; the anticipated benefits from the acquisition of Aurora, including our beliefs that the acquisition will be an excellent fit with our business model and will provide shareholders with exposure to projects with attractive capital efficiencies; our expectations that the Aurora assets have infrastructure in place that support future annual production growth and that such assets will provide material production, long-term growth and high quality reserves with upside potential; anticipated effect of the acquisition of Aurora on us, including our funds from operations; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; the timing of completion of the acquisition of Aurora; our plans to establish new revolving credit facilities and a term loan for us and a borrowing base facility for Aurora's U.S. subsidiary following closing of the Arrangement; payment of the purchase price for the acquisition of Aurora, including the use of proceeds from the subscription receipt financing and our plans to draw on the new revolving credit facilities and term loan; our plans for financing the tender offers for the senior notes of Aurora USA Oil & Gas, Inc. (the "Aurora Note Tender Offers"); our plan to increase the dividend on our common shares upon completion of the acquisition of Aurora; and the level of funds from operations to be generated in 2014. 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. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Total monetary debt is not a measurement based on GAAP in Canada. Baytex defines total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans. Baytex believes that this measure assists in providing a more complete understanding of its cash liabilities.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product sales price less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. Baytex's determination of operating netback may not be comparable with the calculation of similar measures by other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 59,502 boe/d (89% oil and NGL) during Q1/2014, an increase of 2% from Q4/2013 and 15% from Q1/2013.

Capital expenditures for exploration and development activities totaled $172.4 million in Q1/2014 and included the drilling of 153 (119.1 net) wells with a 99% (98% net) success rate.

On March 19, 2014, we entered agreements to acquire certain assets in the Peace River area in exchange for certain assets in the Lloydminster area. The exchange, which has an expected closing date of May 1, 2014, includes the purchase of approximately 1,000 bbl/d of heavy oil in the Peace River area and the sale of approximately 1,150 bbl/d of heavy oil in the Lloydminster area.

Our full-year 2014 production guidance remains unchanged at 60,000 to 62,000 boe/d with budgeted exploration and development expenditures of $485 million. We expect to provide revised guidance for 2014 within a few weeks following the completion of the acquisition of Aurora.

Wells Drilled – Three Months Ended March 31, 2014

	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	92	61.9	–	–	–	–	13	13.0	2	2.0	107	76.9
Peace River area	8	8.0	–	–	–	–	24	24.0	–	–	32	32.0
	100	**69.9**	**–**	**–**	**–**	**–**	**37**	**37.0**	**2**	**2.0**	**139**	**108.9**
Light oil, NGL and natural gas												
Western Canada	6	5.7	–	–	2	2.0	–	–	–	–	8	7.7
North Dakota	6	2.5	–	–	–	–	–	–	–	–	6	2.5
	12	**8.2**	**–**	**–**	**2**	**2.0**	**–**	**–**	**–**	**–**	**14**	**10.2**
Total	**112**	**78.1**	**–**	**–**	**2**	**2.0**	**37**	**37.0**	**2**	**2.0**	**153**	**119.1**

In Q1/2014, heavy oil production averaged 45,232 bbl/d, an increase of 5% from Q4/2013 and 21% from Q1/2013. During Q1/2014, we drilled 100 (69.9 net) oil wells, 37 (37.0 net) stratigraphic wells, and two (2.0 net) dry and abandoned wells on our heavy oil properties.

Production from our Peace River area properties averaged approximately 25,800 bbl/d in Q1/2014, an increase of 8% from Q4/2013 and 37% from Q1/2013. We drilled eight (8.0 net) cold horizontal producers encompassing a total of 104 laterals, and 24 (24.0 net) stratigraphic test wells, for a 100% success rate in the Peace River area.

We are pleased to recognize a significant safety performance milestone which was recently achieved by the crews of Precision Drilling Rig #294 which have worked for Baytex for more than 11 years without a recordable incident. We value the relationship we have with Precision Drilling and the other key vendors who help us to execute our capital programs while achieving exemplary safety performance.

In Q1/2014, the Alberta Energy Regulator ("AER") concluded the public proceeding concerning odours and emissions associated with heavy oil production in the Peace River area. The AER hearing panel issued their recommendations on March 31 and the AER announced on April 15 that it had accepted all recommendations of the panel within its jurisdiction. On April 15, the AER also released the revised Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting, which will take effect on June 16, 2014. We support the AER initiatives and believe our operations are compliant with existing regulations and will be compliant with the new regulations within the specified timelines. Our gas conservation activities and plans at Peace River are consistent with the revised AER initiatives.

In the Cliffdale area of Peace River, 15 wells drilled in 2013 ("Pad 2") are currently producing as planned under primary conditions to create the initial voidage required for the cyclic steam stimulation process. We expect steam injection at Pad 2 to commence in mid-2014.

In our Lloydminster heavy oil area, Q1/2014 drilling included 46 (35.8 net) horizontal oil wells, 46 (26.1 net) vertical oil wells, 13 (13.0 net) stratigraphic test wells, and 2 (2.0 net) dry holes for a 98% (97% net) success rate. Steam injection commenced at the Gemini steam-assisted gravity drainage pilot project on January 24, 2014 and first oil production is projected to occur in Q2/2014.

Financial Review

We generated FFO of $170.8 million ($1.36 per basic share) during Q1/2014, representing a 16% increase from Q4/2013 and a 68% increase from Q1/2013. These increases were the result of higher realized commodity prices and higher sales volumes during 2014.

The average WTI price for Q1/2014 was US$98.68/bbl, representing a 1% increase from Q4/2013 and a 5% increase from Q1/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 23% in Q1/2014, as compared to 33% in Q4/2013 and 34% in Q1/2013. The tightening of the WCS differentials in the three months ended March 31, 2014 was due to weather related production issues limiting supply, low inventory levels, increased take away capacity on pipe and rail and overall robust crude oil demand. As a result of higher WCS prices, our realized total oil and NGL price of $73.12/bbl in Q1/2014 (inclusive of our physical hedging gains) increased by 14% from $63.91/bbl in Q4/2013.

Market conditions remain positive with the forward market indicating a WCS average differential of approximately 20% for the remainder of this year. The improved market conditions reflect a number of positive catalysts unfolding in 2014, including increased refinery demand in the U.S. Midwest, a continued increase in crude by rail volumes and a number of pipeline capacity improvements and expansion projects.

We have taken advantage of the recent strength in WTI prices and the weaker Canadian dollar to add to our hedge portfolio. For Q2/2014, we have entered into hedges on approximately 62% of our WTI exposure at a weighted average price of US$99.47/bbl, 43% of our exposure to WCS price differentials primarily through a combination of long term physical supply contracts and rail delivery, 55% of our natural gas price exposure and 35% of our exposure to currency movements between the U.S. and Canadian dollars. In addition, we have fully hedged our exposure to Australian dollars in anticipation of the acquisition of Aurora. Details of our hedging contracts are contained in the notes to our financial statements.

As part of our hedging program, we are focusing on opportunities to further mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail. In Q1/2014, 22,500 bbl/d (approximately 50%) of our heavy oil volumes were delivered to market by rail, as compared to 17,500 bbl/d for full-year 2013. For Q2/2014, we expect our heavy oil volumes on rail to average approximately 25,000 to 26,000 bbl/d.

Total monetary debt at the end of Q1/2014 was $832.3 million, representing a debt-to-FFO ratio of 1.2 times based on FFO over the trailing twelve-month period. At March 31, 2014, we had $549.4 million in undrawn credit capacity on existing facilities and no long-term debt maturities prior to 2017. We continue to have a strong balance sheet and ample liquidity to allow us to execute our growth and income model.

Acquisition of Aurora

On February 6, 2014, we entered an agreement to acquire all of the ordinary shares of Aurora for $4.10 (Australian dollars) per share by way of a scheme of arrangement under the Corporations Act 2001 (Australia) (the "Arrangement"). The total purchase price for Aurora is estimated at $2.6 billion (including the assumption of approximately $0.7 billion of indebtedness). The acquisition enhances our growth and income business model, delivers production and reserves per share growth and provides attractive capital efficiencies for future investment. The acquisition is accretive to our funds from operations while maintaining a strong balance sheet.

Aurora's primary asset consists of 22,200 net contiguous acres in the prolific Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. Aurora's first quarter 2014 gross production was 28,671 boe/d (81% liquids) of predominantly light, high-quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. In addition, these assets have significant future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

The Arrangement is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of the shareholders of Aurora. Regulatory approvals include approval of the Australian Foreign Investment Review Board and the applicable approvals required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, both of which have been received.

The Federal Court of Australia has approved the dispatch of the scheme booklet and ordered that a meeting of Aurora shareholders be convened to consider and vote on the Arrangement. The scheme meeting will be held on Wednesday, May 21, 2014 at 9:30 a.m. (Perth time). The Arrangement must be approved by: (i) at least 75% of the votes cast by Aurora shareholders; and (ii) by a majority, in number, of the Aurora shareholders, who cast votes. Completion of the Arrangement is anticipated to occur in the first half of June.

To finance the acquisition of Aurora, we completed the issuance of 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. We also entered into a commitment letter with a Canadian chartered bank for the provision of new revolving credit facilities in the amount of $1.0 billion (to replace the $850 million revolving credit facilities of Baytex Energy Ltd.), a new two-year $200 million non-revolving loan and a new borrowing base facility for a U.S. subsidiary of Aurora. The new facilities will be available upon closing of the arrangement.

In order to simplify our debt capital structure following the completion of the Arrangement, we have commenced cash tender offers relating to the US$665 million of outstanding senior notes of Aurora USA Oil & Gas, Inc., a wholly-owned subsidiary of Aurora. We expect to obtain the funds necessary to complete the tender offers from one or more debt financing transactions, including potential debt securities offerings or an increase in available credit under existing or new credit facilities.

9% Dividend Increase

We are committed to our growth and income model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. Through the combination of an expanded inventory of high capital efficiency projects and an improved outlook for heavy oil differentials, we remain confident in our business plan going forward. Accordingly, we have committed to increase the monthly dividend on our common shares by 9% to $0.24 from $0.22 per share, subject to the completion of the Aurora acquisition.

Conclusion

Our strong operating results and an improved outlook for heavy oil differentials has Baytex poised to deliver record funds from operations in 2014. Our capital program is being implemented as planned and our operational execution remains on track. Additionally, we previously announced an agreement to acquire Aurora which is expected to close in the first half of June. We are excited about the pending acquisition as it expands our asset portfolio into the Eagle Ford, one of the premier oil resource plays in North America. We continue to have a strong balance sheet and ample liquidity to allow us to execute our growth and income model. Overall, 2014 is shaping up to be an exciting year for Baytex.

We want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
May 1, 2014

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 ended March 31, 2014. This information is provided as of April 30, 2014. 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 first quarter results have been compared with the corresponding period in 2013. 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 ended March 31, 2014, its audited comparative consolidated financial statements for the years ended December 31, 2013 and 2012, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2013. 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 or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

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

NON-GAAP FINANCIAL MEASURES

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

Payout Ratio

We define payout ratio as cash dividends (net of participation in our Dividend Reinvestment Plan ("DRIP")) 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 unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), 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. As sales volumes are not materially different than production volumes, we believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

EBITDA

We define EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items. This measure is used to measure compliance with certain contractual debt covenants. For a reconciliation of EBITDA to net income, see "Funds from Operations, Payout Ratio, Dividends and EBITDA".

RESULTS OF OPERATIONS

Production

	Three Months Ended March 31		
	2014	2013	Change
Daily Production			
Light oil and NGL (bbl/d)	**7,457**	7,920	(6%)
Heavy oil (bbl/d)[1]	**45,232**	37,486	21%
Natural gas (mcf/d)	**40,886**	39,305	4%
Total production (boe/d)	**59,502**	51,957	15%
Production Mix			
Light oil and NGL	**13%**	15%	
Heavy oil	**76%**	72%	
Natural gas	**11%**	13%	

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory. For the three months ended March 31, 2014, heavy oil sales volumes were 56 bbl/d lower than production volumes (three months ended March 31, 2013 – 10 bbl/d lower).*

Production for the three months ended March 31, 2014 averaged 59,502boe/d, an increase of 15% compared to 51,957 boe/d for the same period in 2013 and an increase of 2% compared to 58,304 boe/d in the fourth quarter of 2013. Light oil and natural gas liquids ("NGL") production in the first quarter of 2014 decreased by 6% to 7,457 bbl/d, as compared to 7,920 bbl/d in the first quarter of 2013, primarily due to natural declines in Western Canada. Heavy oil production for the first quarter of 2014 increased by 21% to 45,232bbl/d from 37,486 bbl/d in the first quarter of 2013, primarily due to successful development activities in the Peace River area. Natural gas production increased by 4% to 40.9 mmcf/d for the first quarter of 2014, as compared to 39.3 mmcf/d for the same period in 2013.

Commodity Prices

Crude Oil

For the three months ended March 31, 2014, the West Texas Intermediate ("WTI") oil prompt price averaged US$98.68/bbl, a 5% increase from the average WTI price of US$94.37/bbl in the first quarter of 2013 and a 1% increase from the average WTI price of US$97.46 in the fourth quarter of 2013. In the three months ended March 31, 2014, prices benefited from new pipeline connectivity between Cushing and the U.S. Gulf Coast which led to significant storage withdrawals at Cushing. Refiner activity was relatively strong during the quarter on the back of higher than normal heating oil demand, the start-up of BP's Whiting refinery and a minimal amount of refinery outages.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 23% for the three months endedMarch 31, 2014 compared to 34% for the same period in 2013 and 33% in the fourth quarter of 2013. WCS differentials improved in the three months ended March 31, 2014 due to weather related production issues limiting supply, price supportive inventory levels, increased take away capacity on pipe and rail and overall robust crude oil demand.

Natural Gas

For the three months ended March 31, 2014 the AECO natural gas price averaged $4.76/mcf, a 55% increase compared to $3.08/mcf in the same period of 2013. The increase in natural gas price for the three months ended March 31, 2014 compared to the same period in 2013 is a result of prolonged colder than normal weather experienced since November 2013, that drove both Canadian and U.S. storage levels to multi-year lows.

	Three Months Ended March 31		
	2014	2013	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 98.68	$ 94.37	5%
WCS heavy oil (US$/bbl)[2]	$ 75.55	$ 62.41	21%
Heavy oil differential[3]	23%	34%	
CAD/USD average exchange rate	1.1035	1.0089	9%
Edmonton par oil ($/bbl)	$ 100.18	$ 88.65	13%
AECO natural gas price ($/mcf)[4]	$ 4.76	$ 3.08	55%
Average Sales Prices			
Heavy oil ($/bbl)[5]	$ 70.86	$ 50.77	40%
Physical forward sales contracts gain($/bbl)	$ 0.27	$ 2.70	(90%)
Heavy oil, net ($/bbl)	$ 71.13	$ 53.47	33%
Light oil and NGL ($/bbl)[6]	$ 85.18	$ 76.72	11%
Total oil and NGL, net ($/bbl)	$ 73.12	$ 58.00	26%
Natural gas ($/mcf)[6]	$ 5.22	$ 3.46	51%
Summary			
Weighted average ($/boe)[6]	$ 68.12	$ 50.94	34%
Physical forward sales contracts gain ($/boe)	0.21	1.95	(89%)
Weighted average, net ($/boe)	$ 68.33	$ 52.89	29%

(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 month-ahead index price published by the Canadian Gas Price Reporter.
(5) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(6) Risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.

Average Sales Prices

Our realized heavy oil price during the first quarter of 2014 was $71.13/bbl, or 85% of WCS. This compares to a realized heavy oil price in the first quarter of 2013 of $53.47/bbl, or 85% of WCS. Gains on physical contracts in the first quarter of 2014 declined 89% compared to first quarter of 2013 due to lower hedged volumes in 2014 and higher differentials between WTI and WCS in 2013. The realized price during the first quarter of 2014 also increased due to the decline in the Canadian dollar compared to the first quarter of 2013. During the first quarter of 2014, our average sales price for light oil and NGL was $85.18/bbl, up 11% from $76.72/bbl in the first quarter of 2013, in-line with the increase in the Edmonton par oil benchmark price. Our realized natural gas price for the three months ended March 31, 2014 was $5.22/mcf, up from $3.46/mcf in the first quarter of 2013, in line with the increase in the AECO benchmark.

Gross Revenues

	Three Months Ended March 31		
($ thousands except for %)	2014	2013	Change
Oil revenue			
Light oil and NGL	$ 57,166	$ 54,687	5%
Heavy oil	289,213	180,360	60%
Total oil revenue	346,379	235,047	47%
Natural gas revenue	19,195	12,233	57%
Total oil and natural gas revenue	365,574	247,280	48%
Heavy oil blending revenue	20,235	25,665	(21%)
Total petroleum and natural gas revenues	$ 385,809	$ 272,945	41%

Petroleum and natural gas revenues increased 41% to $385.8 million for the three months ended March 31, 2014 from $272.9 million for the same period in 2013. The growth in revenues for the three months ended March 31, 2014 was driven by higher heavy oil volumes and higher commodity prices compared to the first quarter of 2013. Heavy oil blending revenue was down 21% for the three months ended March 31, 2014 due to the decrease in contracted volumes of heavy oil requiring blending diluent. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require condensate blending. The decrease in heavy oil blending revenue is offset by a corresponding decrease in heavy oil blending costs.

Royalties

	Three Months Ended March 31		
($ thousands except for % and per boe)	2014	2013	Change
Royalties	$ 74,880	$ 45,278	65%
Royalty rates:			
Light oil, NGL and natural gas	19.6%	25.4%	
Heavy oil	20.7%	15.7%	
Average royalty rates(1)	20.5%	18.3%	
Royalty expenses per boe	$ 14.00	$ 9.68	45%

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

Total royalties for the first quarter of 2014 increased to $74.9 million from $45.3 million in the first quarter of 2013. Total royalties for the first quarter of 2014 were in line with expectations at 20.5% of oil and natural gas revenue, as compared to 18.3% for the same period in 2013.

Royalty rates in the three months ended March 31, 2014 for light oil, NGL and natural gas were 19.6%, down from 25.4% in the three months ended March 31, 2013 as a result of decreased production on U.S. properties with carry obligations, partially offset by higher realized pricing. Royalty rates for heavy oil increased to 20.7% in the three months ended March 31, 2014 compared to 15.7% in the three months ended March 31, 2013, due to higher commodity prices as well as increased royalty rates on certain farm-in agreements.

Financial Derivatives

	Three Months Ended March 31		
($ thousands)	2014	2013	Change
Realized (loss) gain on financial derivatives(1)			
Crude oil	$ 1,613	$ 6,861	$ (5,248)
Natural gas	(1,187)	343	(1,530)
Foreign currency	(2,035)	666	(2,701)
Interest rate	(4,138)	(3,742)	(396)
Total	$ (5,747)	$ 4,128	$ (9,875)
Unrealized gain (loss) on financial derivatives(2)			
Crude oil	$ (9,312)	$ (10,300)	$ 988
Natural gas	(3,036)	(2,387)	(649)
Foreign currency	21,161	(2,937)	24,098
Interest rate	4,012	3,729	283
Total	$ 12,825	$ (11,895)	$ 24,720
Total gain (loss) on financial derivatives			
Crude oil	$ (7,699)	$ (3,439)	$ (4,260)
Natural gas	(4,223)	(2,044)	(2,179)
Foreign currency	19,126	(2,271)	21,397
Interest rate	(126)	(13)	(113)
Total	$ 7,078	$ (7,767)	$ 14,845

(1) Realized (loss) gain 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.

As part of normal operations in the upstream oil and gas industry, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize a series of financial derivative contracts which are intended to reduce some of the volatility in our operating cash flow.

The realized loss of $5.7 million for the three months ended March 31, 2014 on derivative contracts relates to losses on interest rate swaps as LIBOR remained low, as well as the weakening Canadian dollar against the U.S. dollar and higher natural gas prices at March 31, 2014, as compared to December 31, 2013. The unrealized mark-to-market gain of $12.8 million for the three months ended March 31, 2014 mainly relates to financial derivative contracts to mitigate $1.875 billion of Australian dollar foreign exchange exposure which has an unrealized mark-to-market gain of $31.6 million at March 31, 2014, offset by an unrealized mark-to-market loss on CAD/USD financial derivative contracts. The unrealized gain was also due to settlement of previously recorded unrealized losses on interest rate contracts offset by the strengthening commodity prices at March 31, 2014, compared to December 31, 2013.

A summary of the financial derivative contracts in place as at March 31, 2014 and the accounting treatment thereof are disclosed in note 18 to the consolidated financial statements.

Production and Operating Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2014	2013	Change
Production and operating expenses	$ 68,835	$ 65,216	6%
Production and operating expenses per boe:			
Heavy oil	$ 11.85	$ 13.94	(15%)
Light oil, NGL and natural gas	$ 16.07	$ 13.96	15%
Total	$ 12.87	$ 13.95	(8%)

Production and operating expenses for the three months ended March 31, 2014 increased to $68.8 million from $65.2 million for the same period in 2013. This increase is due to higher production volumes offset by lower costs per unit of production. Production and operating expenses decreased to $12.87/boe for the three months ended March 31, 2014 compared to $13.95/boe for the same period in 2013, due to decreased repairs and maintenance costs, partially offset by higher fuel and electricity costs.

Transportation and Blending Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2014	2013	Change
Blending expenses	$ 20,235	$ 25,665	(21%)
Transportation expenses	24,668	20,471	21%
Total transportation and blending expenses	$ 44,903	$ 46,136	(3%)
Transportation expenses per boe[1]:			
Heavy oil	$ 5.85	$ 5.83	–%
Light oil, NGL and natural gas	$ 0.70	$ 0.62	13%
Total	$ 4.61	$ 4.38	5%

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

Transportation and blending expenses for the first quarter of 2014 were $44.9 million, compared to $46.1 million for the first quarter of 2013.

Blending expenses decreased 21% due to lower volumes of condensate required, partially offset by higher per barrel costs of condensate. The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications and to facilitate its marketing. The cost of blending diluent is recovered in the sale price of the blended product. In the first quarter of 2014, blending expenses were $20.2 million for the purchase of

2,025 bbl/d of condensate at $111.02/bbl, compared to $25.7 million for the purchase of 2,681 bbl/d at $106.37/bbl for the same period last year. The decrease in blending expenses for the three months ended March 31, 2014, as compared to the same period in 2013, is due to higher volumes of heavy oil being transported by rail which does not require blending diluent.

Transportation expenses increased 21% due to higher sales volumes and higher average per unit transportation expense. Transportation expenses per boe increased 5% to $4.61/boe for the three months ended March 31, 2014, as compared to $4.38/boe for the same period of 2013, mainly due to a higher weighting in the production mix towards heavy oil in the current period.

Operating Netback

	Three Months Ended March 31		
($ per boe except for % and volume)	2014	2013	Change
Sales volume (boe/d)	**59,446**	51,947	14%
Operating netback[1]:			
Sales price	**$ 68.33**	$ 52.89	29%
Less:			
Royalties	**14.00**	9.68	45%
Production and operating expenses	**12.87**	13.95	(8%)
Transportation expenses	**4.61**	4.38	5%
Operating netback before financial derivatives	**$ 36.85**	$ 24.88	48%
Financial derivatives (loss) gain[2]	**(0.30)**	(1.68)	
Operating netback after financial derivatives (loss) gain	**$ 36.55**	$ 23.20	58%

(1) Operating netback table includes revenues and costs associated with sulphur production.

(2) Financial derivatives reflect realized gains on commodity related contracts only and exclude the impact of interest rate swaps.

Evaluation and Exploration Expense

Evaluation and exploration expense for the three months ended March 31, 2014 increased to $10.6 million from $3.6 million for the same period in 2013 due to an increase in both the expiration of undeveloped land leases and the impairment of evaluation and exploration assets that will not be developed.

Depletion and Depreciation

Depletion and depreciation for the three months ended March 31, 2014 increased to $88.6 million from $78.6 million for the same period in 2013 due to overall higher production volumes. On a sales-unit basis, the provision for the first quarter of 2014 was $16.56/boe, compared to $16.81/boe for the same quarter in 2013.

General and Administrative Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2014	2013	Change
General and administrative expenses	**$ 11,899**	$ 11,550	3%
General and administrative expenses per boe	**$ 2.22**	$ 2.47	(10%)

General and administrative expenses for the three months ended March 31, 2014 increased to $11.9 million, as compared to $11.6 million in the first quarter of 2013, mainly due to higher salary expenses. General and administrative expenses decreased to $2.22/boe in the first quarter of 2014, from $2.47/boe in the first quarter of 2013 due to increased production in 2014.

Share-based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan decreased to $7.9 million for the three months ended March 31, 2014 from $8.8 million for the three months ended March 31, 2013. This was mainly due to an increase in both actual forfeitures and the estimated future forfeiture rate on outstanding awards, as well as a decrease in the estimated payout multiplier.

Financing Costs

	Three Months Ended March 31		
($ thousands except for %)	2014	2013	Change
Bank loan and other	$ 2,904	$ 1,615	80%
Long-term debt	7,944	7,662	4%
Accretion on asset retirement obligations	1,741	1,660	5%
Debt financing costs	–	39	(100%)
Financing costs	$ 12,589	$ 10,976	15%

Financing costs for the three months ended March 31, 2014 increased to $12.6 million, compared to $11.0 million in the first quarter of 2013, mainly due to higher outstanding debt levels, partially offset by lower interest rates.

Foreign Exchange

	Three Months Ended March 31		
($ thousands except for % and exchange rates)	2014	2013	Change
Unrealized foreign exchange loss	$ 6,456	$ 3,817	69%
Realized foreign exchange gain	(1,938)	(2,036)	(5%)
Foreign exchange loss	$ 4,518	$ 1,781	154%
CAD/USD exchange rates:			
At beginning of period	1.0636	0.9949	
At end of period	1.1053	1.0156	

The unrealized foreign exchange loss for the three months ended March 31, 2014 and 2013 is mainly due to foreign exchange translation of the U.S. dollar denominated debt outstanding and the effect of movement of the Canadian dollar against the U.S. dollar in the period. The U.S. dollar denominated debt is comprised of the US$150 million Series B senior unsecured debentures.

The unrealized foreign exchange loss of $6.5 million for the first quarter of 2014, and the unrealized loss of $3.8 million for the first quarter of 2013, were mainly the result of the weaker Canadian dollar against the U.S. dollar at both March 31, 2014 (as compared to December 31, 2013) and at March 31, 2013 (as compared to December 31, 2012). The realized foreign exchange gains for the three months ended March 31, 2014 and 2013 were mainly due to our day-to-day U.S. dollar denominated transactions.

Income Taxes

For the three months ended March 31, 2014, deferred income tax expense was $20.4 million, as compared to $3.8 million for the three months ended March 31, 2013.

When compared to the prior period, the increase in deferred income tax expense is primarily the result of an increase in the amount of tax pool claims required to shelter the increased taxable income in the three months ended March 31, 2014 compared to same period in 2013.

Net Income

Net income for the three months ended March 31, 2014 was $47.8 million, compared to net income of $10.1 million for the same period in 2013. The increase in net income was due to higher operating netbacks, higher financial derivative gains and lower share-based compensation, partially offset by higher depletion and depreciation, income taxes, foreign exchange losses and no gain on disposition in the current year.

Other Comprehensive Income

The $11.7 million balance of accumulated other comprehensive income at March 31, 2014 relates to a $1.5 million foreign currency translation gain accumulated to December 31, 2013 combined with a $10.2 million foreign currency translation gain related to the three months ended March 31, 2014. The increased translation gain is due to the weakening of the Canadian dollar against the U.S. dollar at March 31, 2014, compared to December 31, 2013.

Business Combination

On February 6, 2014, we entered an agreement to acquire all of the ordinary shares of Aurora Oil & Gas Limited ("Aurora") for $4.10 (Australian dollars) per share by way of a scheme of arrangement under the Corporations Act 2001 (Australia) (the "Arrangement"). The total purchase price for Aurora is estimated at $2.6 billion (including the assumption of approximately $0.7 billion of indebtedness). Aurora's primary asset consists of 22,200 net contiguous acres in the prolific Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. Aurora's first quarter 2014 gross production was 28,671 boe/d (81% liquids) of predominantly light, high-quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. In addition, these assets have significant future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

The Arrangement is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of the shareholders of Aurora. Regulatory approvals include approval of the Australian Foreign Investment Review Board and the applicable approvals required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, both of which have been received. The Arrangement must be approved by: (i) at least 75% of the votes cast by Aurora shareholders; and (ii) by a majority, in number, of the Aurora shareholders who cast votes. The vote is scheduled for May 21, 2014 and the Arrangement is expected to close in the first half of June 2014.

To finance the acquisition of Aurora, we completed the issuance of 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. We also entered into a commitment letter with a Canadian chartered bank for the provision of new revolving credit facilities in the amount of $1.0 billion (to replace the $850 million revolving credit facilities of Baytex Energy Ltd.), a new two-year $200 million non-revolving loan and a new borrowing base facility for a U.S. subsidiary of Aurora. The new facilities will be available upon closing of the Arrangement.

Subsequent to March 31, 2014, we commenced cash tender offers for the US$665 million of outstanding senior notes of Aurora USA Oil & Gas, Inc, a wholly-owned subsidiary of Aurora. We expect to obtain the funds necessary to complete the tender offers from one or more debt financing transactions, including potential debt securities offerings, or an increase in available credit under existing or new credit facilities.

FUNDS FROM OPERATIONS, PAYOUT RATIO, DIVIDENDS AND EBITDA

Funds from operations, payout ratio and EBITDA 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 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.

EBITDA represents our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items. EBITDA is calculated to measure compliance with our contractual debt covenants.

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

	Three Months Ended March 31	
($ thousands except for %)	2014	2013
Cash flow from operating activities	$ 121,607	$ 95,174
Change in non-cash working capital	55,980	12,782
Asset retirement expenditures	3,896	2,973
Financing costs	(12,589)	(10,976)
Accretion on asset retirement obligations	1,741	1,660
Accretion on debentures and long-term debt	175	159
Funds from operations	$ 170,810	$ 101,772
Dividends declared	$ 83,257	$ 80,959
Reinvested dividends	(19,816)	(24,510)
Cash dividends declared (net of DRIP)	$ 63,441	$ 56,449
Payout ratio	49%	80%
Payout ratio (net of DRIP)	37%	55%

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, a level of judgment is required 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 we would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $63.4 million for the first quarter of 2014 were funded by funds from operations of $170.8 million.

The following table reconciles net income (a GAAP measure) to EBITDA (a non-GAAP measure):

	Three Months Ended	
($ thousands)	March 31, 2014	March 31, 2013
Net income	$ 47,841	$ 10,149
Plus:		
Financing costs	12,589	10,976
Depletion and depreciation	88,593	78,581
Non-cash items(1)	32,460	11,223
EBITDA	$ 181,483	$ 110,929

(1) Non-cash items include share-based compensation, unrealized foreign exchange loss (gain), exploration and evaluation expense, unrealized loss (gain) on financial derivatives, (gain) loss on divestiture of oil and gas properties and deferred income tax expense.

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)	March 31, 2014	December 31, 2013
Bank loan	$ 300,564	$ 223,371
Long-term debt[1]	465,795	459,540
Working capital deficiency[2]	65,909	79,151
Total monetary debt	$ 832,268	$ 762,062

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale, and liabilities related to assets held for sale).

At March 31, 2014, total monetary debt was $832.3 million, as compared to $762.1 million at December 31, 2013. The increase in Bank loan balance at March 31, 2014 as compared to December 31, 2013 was due to a high level of exploration and development expenditures in the first quarter of the year.

The Company's wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established $850 million of extendible credit facilities consisting of a $40.0 million operating loan and an $810.0 million syndicated loan, each of which constitute a revolving credit facility. Both credit facilities currently mature on June 14, 2017. The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity. At March 31, 2014, $300.6 million has been drawn on these credit facilities with $549.4 million remaining available. A copy of the amended and restated credit agreement (and related amendments) which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011, July 10, 2012, January 14, 2013 and August 9, 2013).

The following table lists the financial covenants under the credit facilities and the senior unsecured debentures, and the compliance therewith as at March 31, 2014.

Covenant Description	Maximum Ratio	Position at March 31, 2014
Bank loan		
Senior secured debt to capitalization[1][2]	0.55:1.00	0.15:1.00
Senior secured debt to EBITDA[1]	3.00:1.00	0.42:1.00
Debt to EBITDA[3]	3.50:1.00	1.08:1.00
Long-term debt		
Fixed charge coverage[4]	2:50:1.00	0.07:1.00

(1) "Senior secured debt" is defined as our bank loan.

(2) "Capitalization" is defined as the sum of our bank loan, principal amount of long-term debt and shareholders' equity.

(3) "Debt" is defined as the sum of our bank loan and the principal amount of long-term debt.

(4) Fixed charge coverage is computed as the ratio of financing cost to trailing twelve month EBITDA.

In the event of a material acquisition, certain of the financial covenants are relaxed for up to two quarter ends following the closing of such material acquisition, provided that in each quarter: (i) the senior secured debt to EBITDA ratio shall not exceed 3.50:1.00; (ii) the debt to EBITDA ratio shall not exceed 4.00:1.00; and (iii) the sole cause of such ratios exceeding the levels set forth above is due to the material acquisition. If we exceed any of the covenants under the credit facilities, we would be required to repay, refinance or renegotiate the loan terms and conditions which may restrict our ability to pay dividends to our shareholders.

The weighted average interest rate on the bank loan for the three months ended March 31, 2014 was 4.33% (three months ended March 31, 2013 – 5.68%).

On July 19, 2012, we issued $300 million principal amount of Series C senior unsecured debentures bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. 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. These debentures are unsecured and are subordinate to 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 credit facilities.

We believe that our 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 March 31	
($ thousands)	2014	2013
Land	$ 1,390	$ 2,985
Seismic	392	558
Drilling and completion	133,458	118,745
Equipment	37,185	44,206
Other	–	28
Total exploration and development	$ 172,425	$ 166,522
Total acquisitions, net of divestitures	673	(42,382)
Total oil and natural gas expenditures	173,098	124,140
Other plant and equipment, net	757	3,370
Total capital expenditures	$ 173,855	$ 127,510

During the three months ended March 31, 2014, we drilled 119.1 net wells, compared to 110.6 net wells in the three months ended March 31, 2013. In 2014, capital investment activity has progressed as planned in our key development areas.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. As at April 28, 2014, we had 126,663,460 common shares and no preferred shares issued and outstanding. We also had 38,433,000 subscription receipts issued and outstanding which are not included in common shares. Each subscription receipt entitles the holder to receive, upon closing of the acquisition of Aurora, one common share of the Company.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of March 31, 2014 and the expected timing for funding these obligations is noted in the table below.

Operating leases	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 261,782	$ 261,782	$ –	$ –	$ –
Dividends payable to shareholders	27,817	27,817	–	–	–
Bank loan(1)	300,564	–	–	300,564	–
Long-term debt(2)	458,387	–	–	–	458,387
Operating leases	40,149	6,515	13,131	13,227	7,276
Processing agreements	77,807	9,569	21,302	12,677	34,259
Transportation agreements	75,259	9,050	20,368	18,649	27,192
Total	$1,241,765	$ 314,733	$ 54,801	$ 345,117	$ 527,114

(1) The bank loan is a covenant-based revolving loan that is extendible annually for a one, two, three or four year period (subject to a maximum four-year term at any time). Unless extended, the revolving period will end on June 14, 2017, with all amounts to be re-paid on such date.
(2) Principal amount of instruments.

We also have 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

Our normal operations expose us to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage 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. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. 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 partially mitigated through a series of derivative contracts intended to reduce some of the volatility of our operating cash flow.

A summary of the risk management contracts in place as at March 31, 2014 and the accounting treatment thereof is disclosed in note 18 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2014	2013				2012		
($ thousands, except per common share amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Gross revenues	385,809	330,712	422,791	341,011	272,945	292,095	299,786	284,248
Net income	47,841	31,173	87,331	36,192	10,149	31,620	26,773	157,280
Per common share – basic	0.38	0.26	0.70	0.29	0.08	0.26	0.22	1.32
Per common share – diluted	0.38	0.25	0.70	0.29	0.08	0.26	0.22	1.30

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 but not limited to: crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our business strategies, plans and objectives; expected royalty rates; the anticipated benefits from the acquisition of Aurora; our expectations that the Aurora assets have infrastructure in place that support future annual production and that such assets will provide material production, long-term growth and high quality reserves with upside potential; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; the timing of completion of the acquisition of Aurora; our plans to establish new revolving credit facilities and a term loan for us and a borrowing base facility for Aurora's U.S. subsidiary following closing of the Arrangement; payment of the purchase price for the acquisition of Aurora, including the use of proceeds from the Subscription Receipt financing and our plans to draw on the new revolving credit facilities and term loan; our plans for financing the tender offers for the senior notes of Aurora USA Oil & Gas, Inc. (the "Aurora Note Tender Offers"); 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: the receipt of regulatory, court and shareholder approvals for the Arrangement; our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; the required financing for the Aurora Note Tender Offers is obtained by Baytex; the satisfaction or waiver of the other conditions to the Aurora Note Tender Offers; 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 for our operating activities; 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; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved 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: the acquisition of Aurora may not be completed on the terms contemplated or at all; failure to realize the anticipated benefits of the acquisition of Aurora; closing of the acquisition of Aurora could be delayed or not completed if we are unable to obtain the necessary regulatory, court and shareholder approvals for the Arrangement or any other approvals required for *completion or, unless waived, some other condition to closing is not satisfied; failure to put in place a borrowing base facility for Aurora's U.S. subsidiary following completion of the Arrangement; the financing required to complete the Aurora Note Tender Offers is not obtained; the Aurora Note Tender Offers and consent solicitations may not be completed on the terms contemplated or at all; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; changes to royalty or mineral/severance tax regimes; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our operating entities and their key personnel and information systems; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; access to technological advances; changes in the demand for oil and natural gas products; involvement in legal, regulatory and tax proceedings; the failure of third parties to comply with confidentiality agreements; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond the control of Baytex. These and additional 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, 2013, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations (if the acquisition of Aurora is completed) and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements 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)*	March 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash	$ 2,340	$ 18,368
Trade and other receivables	182,711	141,651
Crude oil inventory	1,977	1,507
Other assets (note 4)	36,662	–
Financial derivatives	33,681	10,087
Assets held for sale (note 5)	75,693	73,634
	333,064	245,247
Non-current assets		
Exploration and evaluation assets (note 6)	155,212	162,987
Oil and gas properties (note 7)	2,321,187	2,222,786
Other plant and equipment	29,699	29,559
Goodwill	37,755	37,755
TOTAL ASSETS	$ 2,876,917	$ 2,698,334
LIABILITIES		
Current liabilities		
Trade and other payables	$ 261,782	$ 213,091
Dividends payable to shareholders	27,817	27,586
Financial derivatives	29,076	18,632
Liabilities related to assets held for sale (note 5)	12,124	10,241
	330,799	269,550
Non-current liabilities		
Bank loan (note 8)	300,564	223,371
Long-term debt (note 9)	458,387	452,030
Asset retirement obligations (note 10)	224,891	221,628
Deferred income tax liability	270,703	248,401
Financial derivatives	1,469	869
	1,586,813	1,415,849
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 11)	2,046,549	2,004,203
Contributed surplus	43,563	53,081
Accumulated other comprehensive income	11,691	1,484
Deficit	(811,699)	(776,283)
	1,290,104	1,282,485
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,876,917	$ 2,698,334

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per common share amounts) *(unaudited)*	Three Months Ended March 31 2014	2013
Revenues, net of royalties (note 15)	$ 310,929	$ 227,667
Expenses		
Production and operating	68,835	65,216
Transportation and blending	44,903	46,136
Exploration and evaluation (note 6)	10,610	3,582
Depletion and depreciation	88,593	78,581
General and administrative	11,899	11,550
Share-based compensation (note 12)	7,855	9,044
Financing costs (note 16)	12,589	10,976
(Gain) loss on financial derivatives (note 18)	(7,078)	7,767
Foreign exchange loss (note 17)	4,518	1,781
Gain on divestiture of oil and gas properties	–	(20,951)
	242,724	213,682
Net income before income taxes	68,205	13,985
Deferred income tax expense (note 14)	20,364	3,836
Net income attributable to shareholders	$ 47,841	$ 10,149
Other comprehensive income		
Foreign currency translation adjustment	10,207	3,886
Comprehensive income	$ 58,048	$ 14,035
Net income per common share (note 13)		
Basic	$ 0.38	$ 0.08
Diluted	$ 0.38	$ 0.08
Weighted average common shares (note 13)		
Basic	125,939	122,491
Diluted	127,250	123,826

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus[1]	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2012	$ 1,860,358	$ 65,615	$ (12,462)	$ (614,099)	**$ 1,299,412**
Dividends to shareholders	–	–	–	(80,959)	**(80,959)**
Exercise of share rights	9,225	(5,507)	–	–	**3,718**
Vesting of share awards	11,810	(11,810)	–	–	**–**
Share-based compensation	–	9,044	–	–	**9,044**
Issued pursuant to dividend reinvestment plan	23,494	–	–	–	**23,494**
Comprehensive income for the period	–	–	3,886	10,149	**14,035**
Balance at March 31, 2013	$ 1,904,887	$ 57,342	$ (8,576)	$ (684,909)	**$ 1,268,744**
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends	–	–	–	(83,257)	**(83,257)**
Exercise of share rights	5,081	(2,747)	–	–	**2,334**
Vesting of share awards	14,626	(14,626)	–	–	**–**
Share-based compensation	–	7,855	–	–	**7,855**
Issued pursuant to dividend reinvestment plan	22,639	–	–	–	**22,639**
Comprehensive income for the period	–	–	10,207	47,841	**58,048**
Balance at March 31, 2014	$ 2,046,549	$ 43,563	$ 11,691	$ (811,699)	**$ 1,290,104**

(1) Share-based compensation is accumulated in contributed surplus.

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31	
(thousands of Canadian dollars) (unaudited)	2014	2013
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income for the period	$ 47,841	$ 10,149
Adjustments for:		
Share-based compensation (note 12)	7,855	9,044
Unrealized foreign exchange loss (note 17)	6,456	3,817
Exploration and evaluation	10,610	3,582
Depletion and depreciation	88,593	78,581
Unrealized (gain) loss on financial derivatives (note 18)	(12,825)	11,895
Gain on divestitures of oil and gas properties	–	(20,951)
Deferred income tax expense	20,364	3,836
Financing costs (note 16)	12,589	10,976
Change in non-cash working capital	(55,980)	(12,782)
Asset retirement obligations settled (note 10)	(3,896)	(2,973)
	121,607	95,174
Financing activities		
Payment of dividends	(60,386)	(57,244)
Increase in bank loan	77,193	39,448
Issuance of common shares (note 11)	2,334	3,718
Interest paid	(17,311)	(16,538)
	1,830	(30,616)
Investing activities		
Additions to exploration and evaluation assets (note 6)	(7,320)	(4,150)
Additions to oil and gas properties (note 7)	(165,105)	(162,372)
Property acquisitions	(673)	–
Proceeds from divestiture of oil and gas properties	–	42,382
Additions to other plant and equipment, net of disposals	(757)	(3,370)
Change in non-cash working capital	33,531	61,831
	(140,324)	(65,679)
Impact of foreign currency translation on cash balances	859	(485)
Change in cash	(16,028)	(1,606)
Cash, beginning of period	18,368	1,837
Cash, end of period	$ 2,340	$ 231

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at March 31, 2014 and December 31, 2013 and for the three months ended March 31, 2014 and 2013
(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 ("IAS") 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 ("IFRS") and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2013. The Company's accounting policies are unchanged compared to December 31, 2013 except as listed in note 3 "Changes in Accounting Policies". The use of estimates and judgments is also consistent with the December 31, 2013 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on April 30, 2014.

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. CHANGES IN ACCOUNTING POLICIES

Levies

IFRS Interpretations Committee ("IFRIC") 21 "Levies" is effective January 1, 2014, and clarifies the recognition requirements concerning a liability to pay a levy imposed by a government, other than an income tax. The interpretation clarifies that the obligating event which gives rise to a liability is the activity that triggers the payment of the levy in accordance with the relevant legislation. The retrospective adoption of this standard did not have a material impact on the Company's consolidated financial statements.

Financial Instruments: Presentation

IAS 32 "Financial Instruments: Presentation" is effective January 1, 2014, and has been amended to clarify certain requirements for offsetting financial assets and liabilities. IAS 32 relates to presentation and disclosure and the retrospective adoption of this standard did not have a material impact on the Company's consolidated financial statements.

4. OTHER ASSETS

Other assets include underwriters' fees relating to the issuance of the subscription receipts and certain debt issuance costs related to the refinancing. Upon completion of the acquisition, fees related to the subscription receipts will be netted against the proceeds of common shares issued and refinancing costs will be amortized once the refinancing is completed. In the event the acquisition is not completed, the subscription receipts will be refunded with earned interest and all fees will be recorded as an expense.

5. ASSETS HELD FOR SALE

In March 2014, Baytex entered agreements to exchange certain heavy oil assets in Saskatchewan and in return, receive certain heavy oil assets in the Peace River area of Alberta. At March 31, 2014, these assets and related liabilities were measured at carrying amount which was the lower of their carrying amount and estimated fair value less costs to sell. No fair value adjustment was recognized in the period. The Company has not recognized any depletion related to the assets held for sale subsequent to the approval of the exchange in December 2013. The Company expects to complete the exchange in the second quarter of 2014. Assets held for sale include $0.3 million of exploration and evaluation assets and $75.4 million of oil and gas properties. Liabilities related to assets held for sale include $12.1 million of asset retirement obligations.

6. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2012	**$ 240,015**
Capital expenditures	11,846
Property acquisition	3,060
Exploration and evaluation expense	(10,286)
Transfer to oil and gas properties	(82,886)
Divestitures	(1,109)
Assets held for sale (note 5)	(305)
Foreign currency translation	2,652
As at December 31, 2013	**$ 162,987**
Capital expenditures	7,320
Property acquisitions	393
Exploration and evaluation expense	(10,610)
Transfer to oil and gas properties	(6,296)
Foreign currency translation	1,418
As at March 31, 2014	**$ 155,212**

7. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	539,054
Corporate acquisition	108
Property acquisitions	100
Transferred from exploration and evaluation assets	82,886
Assets held for sale (note 5)	(110,386)
Change in asset retirement obligations	(28,734)
Divestitures	(33,907)
Foreign currency translation	16,338
As at December 31, 2013	**$ 3,223,768**
Capital expenditures	165,105
Property acquisitions	280
Transferred from exploration and evaluation assets	6,296
Assets held for sale (note 5)	(2,059)
Change in asset retirement obligations	7,184
Foreign currency translation	10,995
As at March 31, 2014	**$ 3,411,569**

Accumulated depletion	
As at December 31, 2012	**$ 720,733**
Depletion for the period	325,793
Divestitures	(10,191)
Assets held for sale (note 5)	(37,057)
Foreign currency translation	1,704
As at December 31, 2013	**$ 1,000,982**
Depletion for the period	87,926
Foreign currency translation	1,474
As at March 31, 2014	**$ 1,090,382**

Carrying value	
As at December 31, 2013	**$ 2,222,786**
As at March 31, 2014	**$ 2,321,187**

8. BANK LOAN

As at	March 31, 2014	December 31, 2013
Bank loan	$ 300,564	$ 223,371

The Company's wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and an $810.0 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, 3 or 4 year period (subject to a maximum four-year term at any time). Unless extended, the revolving period will end on June 14, 2017 with all amounts to be re-paid on such date. The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity. 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 substantially 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.

The weighted average interest rate on the bank loan for the three months ended March 31, 2014 was 4.33% (5.68% for the three months ended March 31, 2013).

9. LONG-TERM DEBT

As at	March 31, 2014	December 31, 2013
6.75% Series B senior unsecured debentures (US$150,000 – principal) due February 17, 2021	$ 163,907	$ 157,673
6.625% Series C senior unsecured debentures (Cdn$300,000 – principal) due July 19, 2022	294,480	294,357
	$ 458,387	$ 452,030

Accretion expense on debentures of $0.2 million has been recorded in financing costs for the three months ended March 31, 2014 (three months ended March 31, 2013 – $0.2 million).

10. ASSET RETIREMENT OBLIGATIONS

	March 31, 2014	December 31, 2013
Balance, beginning of period	$ 221,628	$ 265,520
Liabilities incurred	3,743	14,901
Liabilities settled	(3,896)	(12,076)
Liabilities divested	–	(1,409)
Accretion	1,741	7,011
Change in estimate[1]	3,441	(42,226)
Liabilities related to assets held for sale (note 5)	(1,883)	(10,241)
Foreign currency translation	117	148
Balance, end of period	$ 224,891	$ 221,628

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

11. 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 March 31, 2014, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	802	10,586
Transfer from contributed surplus on exercise of share rights	–	20,333
Transfer from contributed surplus on vesting and conversion of share awards	555	24,542
Issued pursuant to dividend reinvestment plan	2,167	88,384
Balance, December 31, 2013	**125,392**	**$ 2,004,203**
Issued on exercise of share rights	132	2,334
Transfer from contributed surplus on exercise of share rights	–	2,747
Transfer from contributed surplus on vesting and conversion of share awards	352	14,626
Issued pursuant to dividend reinvestment plan	566	22,639
Balance, March 31, 2014	**126,442**	**$ 2,046,549**

Monthly dividends of $0.22 per common share were declared by the Company during the three months ended March 31, 2014 and 2013 for total dividends declared of $83.3 million ($69.1 million net of dividend reinvestment) and $81.0 million ($56.4 million net of dividend reinvestment), respectively.

12. EQUITY BASED PLANS

Share Award Incentive Plan

The Company recorded compensation expense related to the share awards of $7.9 million for the three months ended March 31, 2014 (three months ended March 31, 2013 – $8.8 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 a forfeiture rate, which has been estimated at a weighted average of 9.7% 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 $40.36per restricted award and performance award granted during the three months ended March 31, 2014 (three months ended March 31, 2013 – $44.20 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Number of share awards *(000s)*
Balance, December 31, 2012	**566**	**388**	**954**
Granted	437	374	811
Vested and converted to common shares	(215)	(142)	(357)
Forfeited	(65)	(40)	(105)
Balance, December 31, 2013	**723**	**580**	**1,303**
Granted	350	273	623
Vested and converted to common shares	(144)	(102)	(246)
Forfeited	(32)	(23)	(55)
Balance, March 31, 2014	**897**	**728**	**1,625**

Share Rights Plan

No new grants have been made under the Share Rights Plan since December 31, 2010. All outstanding share rights have been fully expensed and are exercisable.

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

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2012[(1)]	**1,525**	**$ 16.79**
Exercised[(2)]	(802)	13.53
Forfeited[(1)]	(6)	27.77
Balance, December 31, 2013[(1)]	**717**	**$ 17.69**
Exercised[(2)]	(132)	17.62
Balance, March 31, 2014[(1)]	**585**	**$ 17.33**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price for dividends and distributions.

(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.

13. NET INCOME PER SHARE

	Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	$ 47,841	125,939	$ 0.38	$ 10,149	122,491	$ 0.08
Dilutive effect of share awards	–	1,047	–	–	707	–
Dilutive effect of share rights	–	264	–	–	628	–
Net income – diluted	$ 47,841	127,250	$ 0.38	$ 10,149	123,826	$ 0.08

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2014	2013
Net income before income taxes	$ 68,205	$ 13,985
Expected income taxes at the statutory rate of 25.47% (2013 – 25.51%)[(1)]	17,372	3,568
Increase (decrease) in income taxes resulting from:		
Share-based compensation	2,000	2,307
Effect of rate adjustments for foreign jurisdictions	(394)	(1,996)
Other	1,386	(43)
Income tax expense	$ 20,364	$ 3,836

(1) The change in statutory rate is mainly related to changes in the provincial apportionment of income.

15. REVENUES

	Three Months Ended March 31	
	2014	2013
Petroleum and natural gas revenues	$ 384,422	$ 271,789
Royalty charges	(74,880)	(45,278)
Royalty income	1,387	1,156
Revenues, net of royalties	$ 310,929	$ 227,667

16. FINANCING COSTS

	Three Months Ended March 31	
	2014	2013
Bank loan and other	$ 2,904	$ 1,615
Long-term debt	7,944	7,662
Accretion on asset retirement obligations	1,741	1,660
Debt financing costs	–	39
Financing costs	$ 12,589	$ 10,976

17. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended March 31	
	2014	2013
Unrealized foreign exchange loss	$ 6,456	$ 3,817
Realized foreign exchange gain	(1,938)	(2,036)
Foreign exchange loss	$ 4,518	$ 1,781

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Foreign Currency Risk

At March 31, 2014, the Company had in place the following currency derivative contracts relating to operations:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	April to June 2014	US$4.00 million	1.0972	(2)
Monthly average rate forward	April to June 2014	US$2.00 million	1.0976	(2)
Monthly range forward spot sale	April to June 2014	US$1.00 million	1.0800 - 1.1150	(1)(5)
Contingent monthly forward spot sale	April to June 2014	US$0.50 million	1.1150	(1)(6)
Monthly average collar	April to December 2014	US$1.00 million	1.0300 - 1.0600	(1)(5)
Monthly average rate forward	April to December 2014	US$3.50 million	1.0671	(2)
Monthly forward spot sale	April to December 2014	US$9.50 million	1.0517	(2)
Monthly average collar	April to December 2014	US$0.50 million	1.0350 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$0.50 million	1.0375 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$1.00 million	1.0400 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$1.00 million	1.0430 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$1.00 million	1.0450 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$1.50 million	1.0500 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$0.50 million	1.0550 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$0.50 million	1.0575 - 1.1100	(1)(3)
Monthly average collar	April to December 2014	US$0.50 million	1.0650 - 1.1100	(1)(3)
Monthly average range forward	April to December 2014	US$2.00 million	1.0800 - 1.1400	(1)(5)
Contingent average rate forward	April to December 2014	US$1.00 million	1.1400	(1)(6)
Monthly forward spot sale	April 2014 to December 2015	US$1.00 million	1.1300	(1)
Monthly range forward spot sale	July to December 2014	US$1.00 million	1.0550 - 1.1303	(1)(5)
Contingent monthly forward spot sale	July to December 2014	US$0.50 million	1.1303	(1)(6)
Sold call option	July to December 2014	US$3.00 million	1.0670	(1)(4)
Sold call option	July to December 2014	US$3.00 million	1.1200	(1)(4)
Sold call option	July to December 2014	US$4.00 million	1.0520	(1)(4)
Sold call option	July 2014 to December 2015	US$0.50 million	1.0823	(1)(4)
Sold call option	July 2014 to December 2015	US$1.00 million	1.0996	(1)(4)
Sold call option	July 2014 to December 2015	US$4.00 million	1.1100	(1)(4)
Monthly forward spot sale	July 2014 to December 2015	US$1.00 million	1.0900	(1)
Monthly average rate forward	July 2014 to December 2015	US$1.50 million	1.0950	(1)
Monthly average collar	January 2015	US$6.50 million	1.0675 - 1.1200	(1)(3)
Monthly average range forward	January 2015	US$0.50 million	1.0950 - 1.1200	(1)(5)
Contingent average rate forward	January 2015	US$0.50 million	1.1200	(1)(6)
Monthly forward spot sale	January 2015 to December 2015	US$1.00 million	1.1000	(1)
Sold call option	January 2015 to December 2015	US$0.50 million	1.1052	(1)(4)
Monthly average range forward	February 2015 to March 2015	US$0.50 million	1.1050 - 1.1350	(1)(5)
Contingent average rate forward	February 2015 to March 2015	US$0.50 million	1.1350	(1)(6)

(1) Actual contract rate (CAD/USD).
(2) Based on the weighted average contract rates (CAD/USD).
(3) Settlement price above the upper end of the price collar will result in settlement at the lower end of the price collar.
(4) Counterparty has the option to enter into a monthly average rate forward for the periods, amounts per month and sales prices noted.
(5) Settlement price below or at the lower strike price results in settlement at the lower strike price. Settlement price above the lower strike price results in settlement at the higher strike price.
(6) Settlement required if settlement price is above the strike price.

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

	Assets		Liabilities	
	March 31, 2014	December 31, 2013	**March 31, 2014**	December 31, 2013
U.S. dollar denominated	**US$122,501**	US$102,637	**US$205,157**	US$194,924

Baytex has entered into financial derivative contracts to mitigate $1.875 billion of Australian dollar foreign exchange exposure, at a maximum ceiling rate of approximately $1.0115 AUD/CAD.

Interest Rate Risk

As at March 31, 2014, 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	April to September 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	April to September 2014	US$90.0 million	4.39%	3-month LIBOR

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.

Financial Derivative Contracts

At March 31, 2014, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	April to June 2014	16,750 bbl/d	US$100.31	WTI
Fixed – Sell	April to September 2014	1,500 bbl/d	US$98.65	WTI
Fixed – Sell	April to December 2014	3,500 bbl/d	US$95.43	WTI
Fixed – Buy	April to December 2014	380 bbl/d	US$101.06	WTI
Basis swap	April to December 2014	2,000 bbl/d	WTI less US$22.90	WCS
Basis swap	June to December 2014	1,000 bbl/d	WTI less US$19.30	WCS
Fixed – Sell	July to September 2014	3,000 bbl/d	US$99.50	WTI
Fixed – Sell	July to December 2014	3,000 bbl/d	US$95.40	WTI
Sold call option(2)	July 2014 to March 2015	3,000 bbl/d	US$95.00	WTI
Sold call option(2)	July 2014 to March 2015	3,000 bbl/d	US$96.00	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	April to October 2014	3,250 mmBtu/d	US$4.20	NYMEX
Fixed – Sell	April to December 2014	2,000 mmBtu/d	US$4.45	NYMEX
Price collar	April to October 2014	5,000 mmBtu/d	US$3.90-US$4.50	NYMEX
Fixed – Sell	April to October 2014	2,500 mmBtu/d	US$4.18	NYMEX
Basis swap	April to October 2014	5,000 mmBtu/d	NYMEX less US$0.3150	AECO
Fixed – Sell	April 2014 to March 2015	10,000 mmBtu/d	US$4.08	NYMEX
Basis swap	April 2014 to March 2015	17,750 mmBtu/d	NYMEX less US$0.2225	AECO
Fixed – Sell	November 2014 to March 2015	10,000 mmBtu/d	US$4.31	NYMEX
Sold call option(2)	November 2014 to March 2015	5,000 mmBtu/d	US$4.65	NYMEX
Basis swap	November 2014 to March 2015	5,000 mmBtu/d	NYMEX less US$0.2700	AECO
Sold call option(2)	April 2015 to October 2015	5,000 mmBtu/d	US$4.00	NYMEX

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

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 March 31	
	2014	2013
Realized loss (gain) on financial derivatives	$ 5,747	$ (4,128)
Unrealized (gain) loss on financial derivatives	(12,825)	11,895
(Gain) loss on financial derivatives	$ (7,078)	$ 7,767

Physical Delivery Contracts

As at March 31, 2014, the following physical delivery contracts were 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	Price/Unit[1]
WCS Blend	April to December 2014	2,000 bbl/d	WTI $\times$ 81.00%
WCS Blend	April to December 2014	3,000 bbl/d	WTI less US$19.07

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

At March 31, 2014, Baytex had committed to deliver the volumes of raw bitumen noted below to market on rail:

Heavy Oil	Period	Term Volume
Raw bitumen	April to June 2014	13,000 bbl/d
Raw bitumen	July to September 2014	12,500 bbl/d
Raw bitumen	October to December 2014	5,000 bbl/d
Raw bitumen	January to December 2015	7,000 bbl/d
Raw bitumen	January to December 2016	5,000 bbl/d

19. AURORA ACQUISITION

On February 6, 2014, Baytex entered an agreement to acquire all of the ordinary shares of Aurora Oil & Gas Limited. ("Aurora") for $4.10 (Australian dollars) per share by way of a scheme of arrangement of the Corporations Act 2001 (Australia) (the "Arrangement"). The total purchase price for Aurora is estimated at $2.6 billion (including the assumption of approximately $0.7 billion of indebtedness). Aurora's assets are primarily in Texas, USA.

The Arrangement is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of the shareholders of Aurora. Regulatory approvals include approval of the Australian Foreign Investment Review Board and the applicable approvals required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, both of which have been received. The Arrangement must be approved by: (i) at least 75% of the votes cast by Aurora shareholders; and (ii) by a majority, in number, of the Aurora shareholders who cast votes. The Arrangement is expected to close in the first half of June 2014.

To finance the acquisition of Aurora, Baytex completed the issuance of 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. Baytex also entered into a commitment letter with a Canadian chartered bank for the provision of new revolving credit facilities in the amount of $1.0 billion (to replace the $850 million revolving credit facilities of Baytex Energy), a new two-year $200 million non-revolving loan and a new borrowing base facility for a U.S. subsidiary of Aurora. The new facilities will be available upon closing of the Arrangement.

Subsequent to March 31, 2014, Baytex commenced cash tender offers relating to the US$665 million of outstanding senior notes of Aurora USA Oil & Gas, Inc., a wholly-owned subsidiary of Aurora. Baytex expects to obtain the funds necessary to complete the tender offers from one or more debt financing transactions, including potential debt securities offerings or an increase in available credit under existing or new credit facilities.

20. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

Baytex filed a Short Form Base Shelf Prospectus on October 25, 2013, 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"), to replace a Short Form Base Shelf Prospectus filed on August 4, 2011. 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 $750 million.

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect 100% 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 and intercompany loans, Baytex has no independent assets or operations.

For purposes of this note, Baytex accounts for investments in their subsidiary undertakings at cost less impairment because one of the Guarantor Subsidiaries owns 100% of the Non-guarantor Subsidiary. If Baytex were to use equity accounting, the results for the period would be affected as indicated below.

Increase (decrease)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiary	Consolidation Adjustments	Total Consolidated
As at and for the three months ended March 31, 2014					
Total assets	$ 254,639	$ 76,719	$ –	$ (331,358)	$ –
Total shareholders' equity	254,639	76,719	–	(331,358)	–
Net income	54,810	1,474	–	(56,284)	–
As at December 31, 2013					
Total assets	$ 199,016	$ 81,798	$ –	$ (280,814)	$ –
Total shareholders' equity	199,016	81,798	–	(280,814)	–
For the three months ended March 31, 2013					
Net income	$ 15,508	$ 6,216	$ –	$ (21,724)	$ –

The following tables present consolidating financial information prepared using the cost method as at March 31, 2014, and December 31, 2013 and for the three months ended March 31, 2014 and 2013 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 Subsidiary	Consolidation Adjustments	Total Consolidated
As at March 31, 2014					
Current assets	$ 215	$ 332,755	$ 94	$ –	$ 333,064
Intercompany advances and investments	1,634,488	102,984	76,710	(1,814,182)	–
Non-current assets	–	2,543,853	–	–	2,543,853
Current liabilities	33,121	297,593	85	–	330,799
Intercompany notes	110,165	491,076	–	(601,241)	–
Non-current liabilities	455,952	800,062	–	–	1,256,014
Shareholders' Equity	$ 1,035,465	$ 1,390,861	$ 76,719	$ (1,212,941)	$ 1,290,104
As at December 31, 2013					
Current assets	$ –	$ 231,719	$ 13,528	$ –	$ 245,247
Intercompany advances and investments	1,809,264	119,404	68,605	(1,997,273)	–
Non-current assets	–	2,453,087	–	–	2,453,087
Current liabilities	40,502	228,713	335	–	269,550
Intercompany notes	36,682	466,836	–	(503,518)	–
Non-current liabilities	449,595	696,704	–	–	1,146,299
Shareholders' Equity	$ 1,282,485	$ 1,411,957	$ 81,798	$ (1,493,755)	$ 1,282,485
For the Three Months Ended March 31, 2014					
Revenues, net of royalties	$ 7,696	$ 311,305	$ 1,502	$ (9,574)	$ 310,929
Operating expenses	–	113,738	–	–	113,738
Other expenses	14,665	35,274	28	(9,574)	40,393
Depletion and depreciation	–	88,593	–	–	88,593
Income tax expense	–	20,364	–	–	20,364
Net income (loss)	$ (6,969)	$ 53,336	$ 1,474	$ –	$ 47,841
For the Three Months Ended March 31, 2013					
Revenues, net of royalties	$ 5,752	$ 228,012	$ 6,233	$ (12,330)	$ 227,667
Operating expenses	–	111,352	–	–	111,352
Other expenses	11,111	24,951	17	(12,330)	23,749
Depletion and depreciation	–	78,581	–	–	78,581
Income tax expense	–	3,836	–	–	3,836
Net income (loss)	$ (5,359)	$ 9,292	$ 6,216	$ –	$ 10,149

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiary	Consolidation Adjustments	Total Consolidated
For the Three Months Ended March 31, 2014					
Cash provided by (used in):					
Operating activities	$ 7,105	$ 106,491	$ 8,011	$ –	$ 121,607
Payment of dividends	(60,386)	–	–	–	(60,386)
Change in bank loan	–	77,193	–	–	77,193
Change in intercompany loans and investments	66,491	(58,386)	(8,105)	–	–
Increase in equity	2,334	–	–	–	2,334
Interest paid	(15,544)	(1,767)	–	–	(17,311)
Financing activities	$ (7,105)	$ 17,040	$ (8,105)	$ –	$ 1,830
Investing activities	$ –	$ (140,324)	$ –	$ –	$ (140,324)
Impact of foreign currency translation on cash balances	–	859	–	–	859
Change in cash	–	(15,934)	(94)	–	(16,028)
Cash, beginning of period	–	4,840	13,528	–	18,368
Cash, end of period	$ –	$ (11,094)	$ 13,434	$ –	$ 2,340
For the three months ended March 31, 2013					
Cash provided by (used in):					
Operating activities	$ 5,547	$ 89,876	$ (249)	$ –	$ 95,174
Payment of dividends	(57,244)	–	–	–	(57,244)
Change in bank loan	–	39,448	–	–	39,448
Change in intercompany loans and investments	63,123	(63,123)	–	–	–
Increase in equity	3,718	–	–	–	3,718
Interest paid	(15,144)	(1,394)	–	–	(16,538)
Financing activities	$ (5,547)	$ (25,069)	$ –	$ –	$ (30,616)
Investing activities	$ –	$ (65,679)	$ –	$ –	$ (65,679)
Impact of foreign currency translation on cash balances	–	(485)	–	–	(485)
Change in cash	–	(1,357)	(249)	–	(1,606)
Cash, beginning of period	–	1,837	–	–	1,837
Cash, end of period	$ –	$ 480	$ (249)	$ –	$ 231

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*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
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Executive Chairman
Baytex Energy Corp.

James L. Bowzer
President and Chief Executive Officer
Baytex Energy Corp.

John A. Brussa(3)(4)
Vice Chairman
Burnet, Duckworth & Palmer LLP

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

Naveen Dargan(1)(2)
Independent Businessman

R. E. T. (Rusty) Goepel(4)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters(1)(2)
Independent Businesswoman

Dale O. Shwed(3)
President and 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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Canadian Imperial Bank of Commerce
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Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank
Wells Fargo Bank

OFFICERS

Raymond T. Chan
Executive Chairman

James L. Bowzer
President and Chief Executive Officer

Rodney D. Gray
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

W. Derek Aylesworth
Vice President

Geoffrey J. Darcy
Vice President, Marketing

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

Brian G. Ector
Vice President, Capital Markets

Neal E. Halstead
Vice President, Finance and Controller

Cameron A. Hercus
Vice President, Corporate Development

Mark A. Montemurro
Vice President, Thermal Projects

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

Richard P. Ramsay
Vice President, Alberta/B.C. Business Unit

Gregory A. Sawchenko
Vice President, Land

AUDITORS

Deloitte LLP

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