Q1 REPORT 2016

SUMMARY

- Generated production of 75,776 boe/d (78% oil and NGL) in Q1/2016;
- Delivered funds from operations ("FFO") of $45.6 million ($0.22 per share) in Q1/2016;
- Realized an operating netback (sales price less royalties, operating and transportation expenses) in Q1/2016 of $5.82/boe ($12.29/boe including financial derivatives gain);
- Produced 41,067 boe/d in the Eagle Ford, an increase of 2% from Q4/2015 and 5% from Q3/2015;
- Advanced the multi-zone potential of our Sugarkane acreage with 19 wells establishing an average 30-day initial production rate of approximately 1,300 boe/d;
- Amended our bank credit facilities and financial covenants to provide increased financial flexibility; and
- Maintained strong levels of financial liquidity with a Senior Secured Debt to Bank EBITDA ratio of 0.61:1.00.

	Three Months Ended		
	March 31, 2016	December 31, 2015	March 31, 2015
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*			
Petroleum and natural gas sales	$ 153,598	$ 229,361	$ 283,384
Funds from operations(1)	45,645	93,095	160,221
Per share – basic	0.22	0.44	0.95
Per share – diluted	0.22	0.44	0.95
Net income (loss)	607	(412,924)	(175,916)
Per share – basic	0.00	(1.96)	(1.04)
Per share – diluted	0.00	(1.96)	(1.04)
Exploration and development	81,685	140,796	147,429
Acquisitions, net of divestitures	(9)	(574)	1,550
Total oil and natural gas capital expenditures	$ 81,676	$ 140,222	$ 148,979
Bank loan(2)	$ 290,465	$ 256,749	$ 780,447
Long-term notes(2)	1,540,546	1,623,658	1,513,002
Long-term debt	1,831,011	1,880,407	2,296,449
Working capital deficiency	150,332	169,498	162,546
Net debt(3)	$ 1,981,343	$ 2,049,905	$ 2,455,995

	Three Months Ended		
	March 31, 2016	December 31, 2015	March 31, 2015
OPERATING			
Daily production			
Heavy oil (bbl/d)	**24,807**	31,733	39,226
Light oil and condensate (bbl/d)	**24,489**	24,930	28,056
NGL (bbl/d)	**10,109**	8,996	8,224
Total oil and NGL (bbl/d)	**59,405**	65,659	75,506
Natural gas (mcf/d)	**98,220**	92,708	91,010
Oil equivalent (boe/d @ 6:1)[4]	**75,776**	81,110	90,675
Benchmark prices			
WTI oil (US$/bbl)	**33.45**	42.18	48.64
WCS heavy oil (US$/bbl)	**19.22**	27.69	33.91
Edmonton par oil ($/bbl)	**40.80**	52.94	51.94
LLS oil (US$/bbl)	**33.24**	43.33	50.55
Baytex average prices (before hedging)			
Heavy oil ($/bbl)[5]	**12.54**	24.41	28.57
Light oil and condensate ($/bbl)	**37.97**	50.17	52.34
NGL ($/bbl)	**18.38**	17.23	19.35
Total oil and NGL ($/bbl)	**24.02**	33.21	36.40
Natural gas ($/mcf)	**2.40**	2.76	3.22
Oil equivalent ($/boe)	**21.93**	30.03	33.54
CAD/USD noon rate at period end	**1.2971**	1.3840	1.2683
CAD/USD average rate for period	**1.3748**	1.3353	1.2308
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**5.39**	6.88	24.87
Low	**1.57**	3.50	16.03
Close	**5.13**	4.48	20.03
Volume traded (thousands)	**483,311**	283,619	122,179
NYSE			
Share price (US$)			
High	**4.15**	5.27	19.99
Low	**1.08**	2.50	13.14
Close	**3.97**	3.24	15.80
Volume traded (thousands)	**154,052**	153,763	24,213
Common shares outstanding (thousands)	**210,689**	210,583	169,001

Notes:

(1) *Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for 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 capital investments and potential future dividends. 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, 2016.*

(2) *Principal amount of instruments.*

(3) *Net 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 current financial derivatives)) and the principal amount of both the long-term notes and the 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; with respect to the shut-in of certain heavy oil production, our expectation that it will preserve the value of our resource base and maximize our funds from operations and the time required to re-start such production; our expectations for annual average production rate and exploration and development capital expenditures for 2016; our target for 2016 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings; the possibility of non-core asset sales; our Eagle Ford shale play, including our assessment of the performance of wells drilled in Q1/2016, initial production rates from new wells, our plans to use "stack and frac" pilots to target three zones in the Eagle Ford formation in addition to the overlying Austin Chalk formation, and the cost to drill, complete and equip a well; 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 partially reduce the volatility in our funds from operations by utilizing financial derivative contracts; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in reducing the volatility in our funds from operations; our liquidity and financial capacity; our belief that the revised credit agreement provides us with increased financial flexibility; the amount that we will save in 2016 on interest expense and standby fees as a result of the amendments to our credit agreement; and our belief that we have adequate liquidity and financial flexibility to execute our business plan, that we are well positioned to benefit from an oil price recovery and that our three core plays provide some of the strongest capital efficiencies in North America. 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.

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.

Oil and Gas Information

Where applicable, oil equivalent 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.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

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 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 capital investments and potential future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Net debt is not a measurement based on GAAP in Canada. We define net debt as the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives)) and the principal amount of both the long-term notes and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in our credit agreements governing our revolving credit facilities. This measure is used to measure compliance with certain financial covenants.

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 revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

Operations Review

Our operating results for the first quarter were consistent with our expectations and reflect a reduced pace of drilling activity in response to the low crude oil price environment. Production of 75,776 boe/d (78% oil and NGL) in Q1/2016 exceeded our first quarter guidance range of 73,000 to 75,000 boe/d, due largely to continued strong operating results in the Eagle Ford. Capital expenditures for exploration and development activities totaled $81.7 million in Q1/2016 and included the drilling of 45 (13.5 net) wells with a 100% success rate.

During the first quarter, we pro-actively shut-in approximately 7,500 boe/d of predominantly low or negative margin heavy oil production in order to optimize the value of our resource base and maximize our funds from operations. Should netbacks improve, we have the ability to restart these wells within one month.

Our 2016 production guidance remains at 68,000 to 72,000 boe/d with budgeted exploration and development expenditures of $225 to $265 million. In 2016, we are targeting capital expenditures to approximate funds from operations in order to minimize additional bank borrowings. Our 2016 program will remain flexible and allows for adjustments to spending based on changes in the commodity price environment. In addition, we may contemplate minor non-core asset sales.

Wells Drilled – Three Months Ended March 31, 2016

	Crude Oil		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	–	–	–	–	–	–	–	–	–	–
Peace River	–	–	–	–	–	–	–	–	–	–
Light oil and natural gas										
Eagle Ford	6	1.9	38	10.6	–	–	–	–	44	12.5
Western Canada	–	–	1	1.0	–	–	–	–	1	1.0
Total	**6**	**1.9**	**39**	**11.6**	**–**	**–**	**–**	**–**	**45**	**13.5**

Our performance in the Eagle Ford was strong during the first quarter with production averaging 41,067 boe/d (77% liquids), an increase of 2% from Q4/2015 and 5% from Q3/2015. Capital expenditures totaled $76.8 million in the Eagle Ford, representing 96% of our exploration and development spending during the quarter. Our pace of development in the Eagle Ford was largely unchanged during the first quarter with approximately six drilling rigs and one frac crew working on our lands. At March 31, 2016, we had 36 (10.7 net) wells waiting on completion.

Significant advancements have been made in the past twelve months to delineate the multi-zone potential of our Sugarkane acreage and we continue to monitor “stack and frac” pilots which target up to three zones in the Eagle Ford formation in addition to the overlying Austin Chalk formation. A recent five-well pad that targeted the Austin Chalk and Upper Eagle Ford formations delivered an average 30-day initial production rate per well of approximately 1,350 boe/d. We currently have 13 multi-zone projects in various stages of execution and production.

In the Eagle Ford in Q1/2016, we participated in the drilling of 44 (12.5 net) wells and commenced production from 34 (10.2 net) wells. Of the 34 wells that commenced production during the first quarter, 19 wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 1,300 boe/d. To-date, we have achieved an approximate 32% reduction in well costs in the Eagle Ford – with wells now being drilled, completed and equipped for approximately US$5.6 million, as compared to US$8.2 million in 2014.

Production in Canada averaged 34,709 boe/d (80% oil and NGL) during Q1/2016 as compared to 40,826 boe/d in Q4/2015. The reduced volumes in Canada reflect the impact of production that was shut-in during the first quarter and the fact there has been no heavy oil drilling since Q3/2015. Capital expenditures for our Canadian assets in Q1/2016 totaled $4.8 million, a decrease from $8.8 million in Q4/2015, and included the drilling of one (1.0 net) liquids-rich natural gas well in the Pembina/O’Chiese region of west-central Alberta.

Financial Review

The first quarter of 2016 was challenging as the global oversupply of crude oil continued to weigh on the market, with crude oil prices hitting a low of US$26/bbl in February. The sharp reduction in crude oil prices had a significant impact on our FFO, which totaled $45.6 million ($0.22 per share) in Q1/2016, as compared to $93.1 million ($0.44 per share) in Q4/2015.

In Q1/2016, the average price for West Texas Intermediate light oil ("WTI") averaged US$33.45/bbl, as compared to US$42.18/bbl in Q4/2015. This 21% decline in the benchmark index resulted in our realized price for light oil and condensate decreasing 24% to $37.97/bbl. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$14.23/bbl in Q1/2016, as compared to US$14.49/bbl in Q4/2015. The lower WTI price in Q1/2016 resulted in a 31% decrease in the price of WCS and a 49% decrease in our realized heavy oil price to $12.54/bbl, as compared to Q4/2015.

We generated an operating netback in Q1/2016 of $5.82/boe ($12.29/boe including financial derivatives gain). The Eagle Ford generated an operating netback of $11.41/boe while our Canadian operations generated an operating loss of $0.77/boe. In Canada, 71% of our production during the quarter was weighted to heavy oil, where price realizations were particularly weak. As a result, we proactively shut-in approximately 7,500 boe/d of predominantly low or negative margin heavy oil production during the first quarter. With WTI currently trading above US$40/bbl, our operating netback in Canada has improved from that reported in the first quarter.

In the Eagle Ford, our assets are located in south Texas, proximal to Gulf Coast markets, with light oil and condensate production priced off a Louisiana Light Sweet crude oil benchmark which typically trades at a premium to WTI. Declining production in the region has increased competition for field supplies resulting in lower transportation and gathering costs and improved price realizations. This relative pricing, combined with low cash costs, contributed positively to our operating netback. During the quarter, the terms of certain post-production NGL processing arrangements in the Eagle Ford were changed, which increased both revenues and operating expenses by approximately $1.00/boe.

During the quarter, we continued to focus on cost reduction initiatives across all of our operations. Operating expenses in Canada decreased 19% on a per boe basis as compared to Q1/2015, despite the impact of fixed costs on lower production volumes. Transportation expenses in Canada have been reduced by 40% on a per boe basis as compared to Q1/2015, due to ongoing optimization within our trucking division and decreased fuel costs.

The following table provides a summary of our operating netbacks for the periods noted.

	Three Months Ended March 31					
	2016			2015		
($ per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Sales Price	**$ 13.55**	**$ 29.02**	**$ 21.93**	$ 27.50	$ 40.84	$ 33.54
Less:						
Royalties	**1.21**	**8.23**	**5.02**	3.01	11.71	6.95
Operating expenses	**10.97**	**9.38**	**10.11**	13.57	7.35	10.75
Transportation expenses	**2.14**	**–**	**0.98**	3.57	–	1.95
Operating netback	**$ (0.77)**	**$ 11.41**	**$ 5.82**	$ 7.35	$ 21.78	$ 13.89
Realized financial derivatives gain	**–**	**–**	**6.47**	–	–	12.48
Operating netback after financial derivatives	**$ (0.77)**	**$ 11.41**	**$ 12.29**	$ 7.35	$ 21.78	$ 26.37

General and administrative expenses were $14.2 million in Q1/2016, as compared to $17.1 million in Q1/2015. The decrease is primarily a result of reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending. As a continued cost control measure, all full-time employee salaries and all annual retainers paid to our directors were reduced by 10% effective March 1, 2016.

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. We realized a financial derivatives gain of $44.6 million in Q1/2016, primarily due to crude oil prices being at levels significantly below those set in our financial derivative contracts.

For the balance of 2016, we have entered into hedges on approximately 44% of our net WTI exposure with 17% fixed at US$62.03/bbl and 27% hedged utilizing a 3-way option structure (as described in note 2 to the table below). We have also entered into hedges on approximately 38% of our net WCS differential exposure and 58% of our net natural gas exposure.

For 2017, we have entered into hedges on approximately 28% of our net WTI exposure hedged utilizing a 3-way option structure (as described in note 2 to the table below). We have also entered into hedges on approximately 8% of our net WCS differential exposure and 32% of our net natural gas exposure.

The unrealized financial derivatives gain with respect to our hedges as at April 26, 2016 was approximately $54 million. The following table summarizes our hedges in place as at May 3, 2016.

	Q2/2016	Q3/2016	Q4/2016	Balance of 2016	Full-Year 2017
CRUDE OIL					
WTI Fixed Hedges					
Volumes (bbl/d)	8,000	5,000	5,000	6,000	–
Price (US$/bbl)	$ 59.84	$ 63.79	$ 63.79	$ 62.03	–
WTI 3-Way Option					
Volumes (bbl/d)	9,500	10,000	10,000	9,833	10,000
Average Ceiling/Floor/Sold Floor (US$/bbl)[2]	$60/$50/$40	$60/$50/$40	$60/$50/$40	$60/$50/$40	$59/$46/$36
Total WTI Hedge Volumes (bbl/d)	17,500	15,000	15,000	15,833	10,000
Hedge (%)[1]	49%	42%	42%	44%	28%
WCS Differential Hedges					
Volumes (bbl/d)	8,000	7,000	7,000	7,333	1,500
WCS Price Relative to WTI (US$/bbl)	$ (13.26)	$ (13.32)	$ (13.40)	$ (13.32)	$ (13.42)
Hedge (%)[1]	42%	37%	37%	38%	8%
NATURAL GAS					
AECO Fixed Hedges					
Volumes (GJ/d)	28,333	32,500	32,500	31,111	10,000
Price ($/GJ)	$ 2.50	$ 2.50	$ 2.39	$ 2.46	$ 2.65
NYMEX Fixed Hedges					
Volumes (mmbtu/d)	15,000	15,000	15,000	15,000	15,000
Price (US$/mmbtu)	$ 2.98	$ 2.98	$ 2.98	$ 2.98	$ 2.79
Total Hedge Volume (mmbtu/d)	41,855	45,804	45,804	44,488	24,478
Hedge (%)[1]	55%	60%	60%	58%	32%

Notes:

(1) *Percentage of hedged volumes is based on the mid-point of our revised 2016 production guidance (excluding NGL), net of royalties.*

(2) *WTI 3-way option consists of a sold call, a bought put and a sold put. In a $60/$50/$40 example, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives WTI when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.*

Financial Liquidity

Total long-term debt at March 31, 2016 was $1.83 billion, comprised of a bank loan of $290 million and senior unsecured notes of $1.54 billion. The decrease in total long-term debt at March 31, 2016, as compared to December 31, 2015, was due to an increase in the Canada-U.S. dollar exchange rate which resulted in the principal amount of our U.S. dollar denominated debt decreasing when converted to Canadian dollars. Our U.S. dollar long-term notes total US$956 million with no material maturities until 2021 and our Canadian dollar long-term notes total C$300 million and mature in 2022. These long-term notes contain no material financial maintenance covenants.

On March 31, 2016, we announced amendments to our bank credit facilities that provide us with increased financial flexibility. The amendments included reducing our credit facilities to US$575 million, granting our bank lending syndicate first priority security with respect to our assets and restructuring our financial covenants. These facilities are not borrowing base facilities and do not require annual or semi-annual reviews. There are no mandatory principal payments prior to maturity in June 2019 and the maturity date can be further extended with the consent of our bank lending syndicate. With this revised agreement, we expect to realize savings of approximately $8 million in 2016 from lower interest expense and standby fees.

The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at March 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	Position as at March 31, 2016	March 31, 2016 to March 31, 2018	June 30, 2018 to Sept. 30, 2018	Dec. 31, 2018	Thereafter
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	0.61:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	4.82:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

Notes:

(1) *"Senior Secured Debt" is defined as the principal amount of our bank loan and other secured obligations under the credit facilities. At March 31, 2016, our Senior Secured Debt totaled $303 million.*

(2) *"Bank EBITDA" is calculated based on terms and conditions set out in the credit agreement which adjusts net income for interest expense, income taxes, certain non-cash items and acquisition and disposition activity. Bank EBITDA is calculated based on a trailing twelve month basis and was $495 million for the twelve months ended March 31, 2016.*

(3) *"Interest Coverage" is computed as the ratio of Bank EBITDA to interest expense on our Senior Secured Debt and long-term notes. Interest expense for the trailing twelve months ended March 31, 2016 was $103 million.*

With these amendments to our bank credit facilities, we expect to have adequate liquidity and financial flexibility to execute our business plan. In addition, we are well positioned to benefit from an oil price recovery as our three core plays provide some of the strongest capital efficiencies in North America.

Conclusion

We continue to meet the challenges brought on by this low oil price environment. During the first quarter, we announced amendments to our bank credit facilities that provide us with increased financial flexibility and we shut-in low or negative margin heavy oil production. To generate the highest netback and rate of return, we focused our capital expenditures on the Eagle Ford. Our operating results in the Eagle Ford were strong during the quarter with production up 2% over Q4/2015 and well costs continuing to decline.

We look forward to executing our plans for 2016 for the ongoing benefit of all stakeholders and we thank you for your continued support.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
May 3, 2016

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, 2016 ("Q1/2016"). This information is provided as of May 2, 2016. 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 Q1/2016 results have been compared with the three months ended March 31, 2015 ("Q1/2015"). 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, 2016, its audited comparative consolidated financial statements for the years ended December 31, 2015 and 2014, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2015. 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, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, net debt and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

The Company considers funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and potential dividends. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income (loss).

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)	**2016**	2015
Cash flow from operating activities	**$ 64,353**	$ 187,900
Change in non-cash working capital	**(20,409)**	(32,125)
Asset retirement expenditures	**1,701**	4,446
Funds from operations	**$ 45,645**	$ 160,221

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position.

The following table summarizes our net debt at March 31, 2016 and December 31, 2015.

($ thousands)	March 31, 2016	December 31, 2015
Bank loan(1)	$ 290,465	$ 256,749
Long-term notes(1)	1,540,546	1,623,658
Working capital deficiency(2)(3)	150,332	169,498
Net debt	$1,981,343	$ 2,049,905

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding current financial derivatives).

(3) In the oil and gas industry, it is not unusual to have a working capital deficiency as accounts receivable arising from sales of production are usually settled within one or two months but accounts payable related to capital and operating expenditures are usually settled over a longer time span (often two to four months) due to vendor billing cycles and internal approval processes.

Operating Netback

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

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants.

The following table reconciles net income (loss) to Bank EBITDA.

	Three Months Ended March 31	
($ thousands)	2016	2015
Net income (loss)	$ 607	$ (175,916)
Plus:		
Financing and interest	29,053	29,410
Unrealized foreign exchange (gain) loss	(86,801)	101,316
Unrealized financial derivatives loss	30,123	88,172
Current income tax (recovery) expense	(1,442)	16,935
Deferred income tax (recovery)	(48,122)	(41,682)
Depletion and depreciation	141,671	174,127
Non-cash items(1)	5,925	12,209
Bank EBITDA	$ 71,014	$ 204,571

(1) Non-cash items include share-based compensation, exploration and evaluation expense and gain (loss) on divestiture of oil and gas properties.

FIRST QUARTER HIGHLIGHTS

The price of West Texas Intermediate light oil ("WTI") reached its lowest point in 13 years in February of 2016 as commodity prices continued to slide during the first half of Q1/2016. Continued oversupply combined with elevated crude oil storage levels weighed on the market with WTI averaging US$33.45/bbl in Q1/2016 compared to US$42.18/bbl in Q4/2015 and US$48.64/bbl in Q1/2015. With the further decrease in commodity prices and the belief that prices will stay "lower for longer", we took several steps to protect our liquidity. We reduced our 2016 exploration and development capital budget by 33% to a range of $225 to $265 million, shut-in approximately 7,500 bbl/d of low or negative margin production throughout the quarter and renegotiated our credit facilities with our banking syndicate.

Production averaged 75,776 boe/d during Q1/2016, representing a 16% reduction from Q1/2015 mainly due to the low or negative margin production being shut-in combined with declining production in Canada resulting from minimal capital investment over the past 15 months. U.S. production averaged 41,067 boe/d for Q1/2016, largely unchanged from 41,076 boe/d in Q1/2015. Canadian production averaged 34,709 boe/d for Q1/2016, a decrease of 30% from Q1/2015.

Funds from operations for Q1/2016 was $45.6 million ($0.22 per basic and diluted share) compared to $160.2 million ($0.95 per basic and diluted share) in Q1/2015. The decrease in FFO was directly attributable to lower commodity prices and lower production volumes in Canada as well as lower realized financial derivatives gain.

Capital expenditures, in response to lower commodity prices, were $81.7 million during Q1/2016, representing a decrease of $65.7 million from the $147.4 million spent in Q1/2015. Capital spending focused on our Eagle Ford assets with 94% of total capital being deployed in the U.S. Spending in the U.S. totaled $76.8 million in Q1/2016 where we drilled 12.5 net wells, completed 9.4 net wells and brought 10.2 net wells on-stream. Activity in Canada was significantly reduced in Q1/2016 as we drilled 1.0 net well and spent $4.9 million compared to 9.1 net wells and $21.3 million in Q1/2015.

At the end of Q1/2016, we amended our credit facilities to provide increased financial flexibility. The amendments include reducing our credit facilities to US$575 million, granting our bank lending syndicate first priority security with respect to our assets and restructuring our financial covenants. At March 31, 2016, we were in compliance with all of our financial covenants and $290.5 million was drawn on the facilities leaving approximately $455.0 million in undrawn credit capacity.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Eagle Ford assets in Texas.

Production

	Three Months Ended March 31					
	2016			2015		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**24,807**	**–**	**24,807**	39,226	–	39,226
Light oil and condensate	**1,566**	**22,923**	**24,489**	2,091	25,965	28,056
NGL	**1,335**	**8,774**	**10,109**	1,239	6,985	8,224
Total liquids (bbl/d)	**27,708**	**31,697**	**59,405**	42,556	32,950	75,506
Natural gas (mcf/d)	**42,003**	**56,217**	**98,220**	42,255	48,755	91,010
Total production (boe/d)	**34,709**	**41,067**	**75,776**	49,599	41,076	90,675
Production Mix						
Heavy oil	**71%**	**–%**	**33%**	79%	–%	43%
Light oil and condensate	**5%**	**56%**	**32%**	4%	63%	31%
NGL	**4%**	**21%**	**13%**	3%	17%	9%
Natural gas	**20%**	**23%**	**22%**	14%	20%	17%

Production for Q1/2016 averaged 75,776 boe/d, a 16% decrease from Q1/2015. Canadian production of 34,709 boe/d decreased 30%, or 14,890 boe/d, from Q1/2015 as we shut-in 7,500 boe/d of low or negative margin production throughout the quarter. The shut in volumes reduced average production in the quarter by approximately 5,000 boe/d, with the remainder due to natural declines from reduced capital spending. U.S. production averaged 41,067 boe/d in Q1/2016 and was relatively unchanged from Q1/2015 with continued capital investment in the Eagle Ford offsetting the production declines.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, funds from operations and our financial position.

Crude Oil

For Q1/2016, the WTI oil prompt averaged US$33.45/bbl, a 31% decrease from the average WTI price of US$48.64/bbl in Q1/2015. The low prices experienced during Q1/2016, as compared to Q1/2015, were due to continued oversupply of crude oil and on-going concerns due to the high levels of storage and potential capacity concerns.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged US$14.23/bbl for Q1/2016 as compared to US$14.73/bbl in Q1/2015. The improvement in the nominal differential was due to increased pipeline capacity from Canada to the U.S. Gulf Coast, which allows WCS pricing to achieve pipeline equivalency with the large waterborne Gulf Coast refinery market.

Natural Gas

For Q1/2016, the AECO natural gas prices averaged $2.11/mcf, a 28% decrease compared to $2.95/mcf in Q1/2015. For Q1/2016, the NYMEX natural gas price averaged US$2.09/mmbtu, a 30% decrease compared to US$2.98/mmbtu in Q1/2015. The decrease in natural gas prices on both indices between periods was driven by historically high production levels and extremely weak weather related demand.

The following table compares selected benchmark prices and our average realized selling prices for Q1/2016 and Q1/2015.

	Three Months Ended March 31		
	2016	2015	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**33.45**	48.64	(31%)
WCS heavy oil (US$/bbl)[2]	**19.22**	33.91	(43%)
LLS oil (US$/bbl)[3]	**33.24**	50.55	(34%)
CAD/USD average exchange rate	**1.3748**	1.2308	12%
Edmonton par oil ($/bbl)	**40.80**	51.94	(21%)
AECO natural gas price ($/mcf)[4]	**2.11**	2.95	(28%)
NYMEX natural gas price (US$/mmbtu)[5]	**2.09**	2.98	(30%)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.

(2) WCS refers to the average posting price for the benchmark WCS heavy oil.

(3) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.

(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").

(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended March 31					
	2016			2015		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 12.54**	**$ –**	**$ 12.54**	$ 28.57	$ –	$ 28.57
Light oil and condensate ($/bbl)	**35.89**	**38.11**	**37.97**	47.84	52.70	52.34
NGL ($/bbl)	**16.91**	**18.60**	**18.38**	24.18	18.49	19.35
Natural gas ($/mcf)	**1.91**	**2.76**	**2.40**	2.68	3.69	3.22
Weighted average ($/boe)[2]	**$ 13.55**	**$ 29.02**	**$ 21.93**	$ 27.50	$ 40.84	$ 33.54

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

Average Realized Sales Prices

U.S. light oil and condensate pricing for Q1/2016 was $38.11/bbl, down 28% from $52.70/bbl in Q1/2015, which is consistent with a 27% decrease in the LLS benchmark (expressed in Canadian dollars). During Q1/2016, our Canadian average sales price for light oil and condensate was $35.89/bbl, down 25% from $47.84/bbl in Q1/2015 compared to a 21% decrease in the benchmark Edmonton par price. Our Canadian realized price decreased more than the benchmark as a higher percentage of our Canadian light oil was a lower grade crude than in Q1/2015 which has increased the discount from the benchmark.

Our realized heavy oil priced for Q1/2016 was $12.54/bbl compared to $28.57/bbl received in Q1/2015. The 56% decrease in realized price was more than the 43% decrease in WCS price as the Company's heavy oil is generally sold at a fixed dollar differential to the WCS benchmark price.

Our realized natural gas price for Q1/2016 was $2.40/mcf, down 25% from $3.22/mcf in Q1/2015. This 25% decrease is in line with the decreases in the AECO and NYMEX benchmarks during these periods.

Our realized NGL price was $18.38/bbl or 40% of WTI (expressed in Canadian dollars) in Q1/2016 compared to $19.35/bbl or 32% of WTI (expressed in Canadian dollars) in Q1/2015. Our realized NGL price has increased in the U.S. in 2016 as the terms of certain post-production NGL processing arrangements in the Eagle Ford were changed, which increased both revenues and operating expenses.

Gross Revenues

	Three Months Ended March 31					
	2016			2015		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 28,308	$ –	$ 28,308	$ 100,856	$ –	$ 100,856
Light oil and condensate	5,114	79,505	84,619	9,001	123,156	132,157
NGL	2,055	14,849	16,904	2,697	11,625	14,322
Total liquids revenue	35,477	94,354	129,831	112,554	134,781	247,335
Natural gas revenue	7,312	14,096	21,408	10,186	16,190	26,376
Total oil and natural gas revenue	42,789	108,450	151,239	122,740	150,971	273,711
Heavy oil blending revenue	2,359	–	2,359	9,673	–	9,673
Total petroleum and natural gas revenues	$ 45,148	$ 108,450	$ 153,598	$ 132,413	$ 150,971	$ 283,384

Total petroleum and natural gas revenues for Q1/2016 of $153.6 million decreased $129.8 million from Q1/2015 with lower commodity prices contributing $80.4 million of the decrease and the remaining $49.4 million from lower production volumes. In Canada, petroleum and natural gas revenues for Q1/2016 totaled $45.1 million, representing a decrease of $87.3 million compared to Q1/2015 with the decrease resulting from lower realized prices and lower production volumes. Petroleum and natural gas revenues of $108.5 million in the U.S. decreased $42.5 million from the prior period due to a decrease in realized prices on all products.

Heavy oil blending revenue of $2.4 million for Q1/2016 decreased $7.3 million compared to Q1/2015. Heavy oil blending revenue decreased as the Company sold less diluent with the decrease in heavy oil production within Canada. Heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. The cost of blending diluent is recovered in the sale price of the blended product. Our heavy oil transported by rail does not require blending diluent. The purchases and sales of blending diluent are recorded as heavy oil blending expense and revenue, respectively.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for Q1/2016 and Q1/2015.

	Three Months Ended March 31					
	2016			2015		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 3,835	$ 30,747	$ 34,582	$ 13,419	$ 43,288	$ 56,707
Average royalty rate(1)	9.0%	28.4%	22.9%	10.9%	28.7%	20.7%
Royalty rate per boe	$ 1.21	$ 8.23	$ 5.02	$ 3.01	$ 11.71	$ 6.95

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

Total royalties for Q1/2016 of $34.6 million decreased 39%, or $22.1 million from Q1/2015, due to the decline in gross revenues. The overall royalty rate in Q1/2016 was 22.9% compared to 20.7% in Q1/2015. The royalty rate has increased as proportionately more of the Company's revenue and royalties are from the U.S. which has a higher royalty rate. Canadian royalties decreased to 9.0% of revenue for Q1/2016, compared to 10.9% of revenue in Q1/2015. Canadian crown royalty rates are partially based on price and with the lower commodity prices during Q1/2016 the Company experienced lower crown royalty rates compared to Q1/2015. The Q1/2016 U.S. royalty rate of 28.4% has remained consistent with the Q1/2015 rate of 28.7% and overall royalties have decreased with the decrease in gross revenues.

Operating Expenses

	Three Months Ended March 31					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.[1]	Total	Canada	U.S.[1]	Total
Operating expenses	$ 34,645	$ 35,035	$ 69,680	$ 60,574	$ 27,181	$ 87,755
Operating expenses per boe	$ 10.97	$ 9.38	$ 10.11	$ 13.57	$ 7.35	$ 10.75

(1) Operating expenses related to the Eagle Ford assets include transportation expenses.

Operating expenses for Q1/2016 of $69.7 million decreased $18.1 million compared to Q1/2015. On a per boe basis, operating expenses for Q1/2016 decreased $0.64/boe to $10.11/boe, compared to $10.75/boe in Q1/2015. Operating expenses per boe have decreased with lower cost Eagle Ford assets comprising a larger percentage of our total production in Q1/2016 as compared to Q1/2015.

Canadian operating expenses of $34.6 million for Q1/2016 decreased $25.9 million compared to Q1/2015. The decrease is a result of lower production volumes and realized cost savings across all of our operations. On a per boe basis, Canadian operating expenses were $10.97/boe in Q1/2016 compared to $13.57/boe in Q1/2015 reflecting the cost savings initiatives during 2016 and the impact of shut-in volumes. As commodity prices improve and the higher cost shut-in volumes are restored, we expect Canadian operating expenses, on a per boe basis, to increase.

U.S. operating expenses were $35.0 million for Q1/2016, a $7.9 million increase compared to Q1/2015. In Q1/2016, the operator of the Eagle Ford property changed certain post-production processing arrangements which increased operating expenses and revenues in the U.S. by approximately $1.00/boe. Operating expenses in the U.S. also increased as the Canadian dollar was weaker against the U.S. dollar in Q1/2016 compared to Q1/2015.

Transportation Expenses

Transportation expenses include the costs to move production from the field to the sales point. The largest component of transportation expenses relates to the trucking of heavy oil to pipeline and rail terminals. The following table compares our transportation expenses for Q1/2016 and Q1/2015.

	Three Months Ended March 31					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.[1]	Total	Canada	U.S.[1]	Total
Transportation expenses	$ 6,775	$ –	$ 6,775	$ 15,949	$ –	$ 15,949
Transportation expense per boe	$ 2.14	$ –	$ 0.98	$ 3.57	$ –	$ 1.95

(1) Transportation expenses related to the Eagle Ford assets have been included in operating expenses.

Transportation expenses for Q1/2016 totaled $6.8 million ($0.98/boe), a decrease of 58%, or $9.2 million, compared to Q1/2015. The decrease is due to lower heavy oil volumes being transported to the sales point, decreased fuel costs and the increased use of lower cost internal trucking. On a per unit basis, costs have decreased as the volumes shut-in were subject to high transportation charges.

Blending Expenses

Blending expenses for Q1/2016 of $2.4 million have decreased $7.3 million or 76%, compared to Q1/2015. Consistent with the decrease in heavy oil blending revenue, blending expenses decreased due to a decrease in both the volume of blending diluent required and the price of blending diluent.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our funds from operations. Financial derivatives are managed at the corporate level and are not allocated between divisions. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price. Changes in the fair value of contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for Q1/2016 and Q1/2015.

	Three Months Ended March 31		
($ thousands)	**2016**	2015	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 41,492**	$108,027	$ (66,535)
Natural gas	**3,134**	5,728	(2,594)
Foreign currency	**–**	(11,921)	11,921
Total	**$ 44,626**	$101,834	$ (57,208)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (34,987)**	$ (69,579)	$ 34,592
Natural gas	**4,864**	(4,998)	9,862
Foreign currency	**–**	(15,456)	15,456
Interest and financing(1)	**–**	1,861	(1,861)
Total	**$ (30,123)**	$ (88,172)	$ 58,049
Total financial derivatives gain (loss)			
Crude oil	**$ 6,505**	$ 38,448	$ (31,943)
Natural gas	**7,998**	730	7,268
Foreign currency	**–**	(27,377)	27,377
Interest and financing	**–**	1,861	(1,861)
Total	**$ 14,503**	$ 13,662	$ 841

(1) Unrealized interest and financing derivatives gain (loss) includes the change in fair value of the call options embedded in our long-term notes.

The realized financial derivatives gain of $44.6 million for Q1/2016, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts.

The unrealized loss of $30.1 million for Q1/2016 is mainly due to the realization, or reversal, of previous unrealized gains recorded at December 31, 2015.

A summary of the financial derivative contracts in place as at March 31, 2016 and the accounting treatment thereof are disclosed in note 15 to the consolidated financial statements.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the periods indicated:

	Three Months Ended March 31					
	2016			2015		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	34,709	41,067	75,776	49,599	41,076	90,675
Operating netback:						
Oil and natural gas revenues	$ 13.55	$ 29.02	$ 21.93	$ 27.50	$ 40.84	$ 33.54
Less:						
Royalties	1.21	8.23	5.02	3.01	11.71	6.95
Operating expenses	10.97	9.38	10.11	13.57	7.35	10.75
Transportation expenses	2.14	–	0.98	3.57	–	1.95
Operating netback	$ (0.77)	$ 11.41	$ 5.82	$ 7.35	$ 21.78	$ 13.89
Realized financial derivatives gain	–	–	6.47	–	–	12.48
Operating netback after financial derivatives	$ (0.77)	$ 11.41	$ 12.29	$ 7.35	$ 21.78	$ 26.37

Exploration and Evaluation Expense

Exploration and evaluation expense includes the derecognition of exploration and evaluation assets and will vary period to period depending on the expiry of leases and assessment of our exploration programs and assets.

Exploration and evaluation expense decreased to $1.5 million for Q1/2016 from $2.4 million in Q1/2015. The decrease for Q1/2016 is due to lower expiries of undeveloped land.

Depletion and Depreciation

	Three Months Ended March 31					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[1]	$ 54,785	$ 86,139	$ 141,671	$ 75,117	$ 98,384	$ 174,127
Depletion and depreciation per boe	$ 17.35	$ 23.05	$ 20.55	$ 16.83	$ 26.61	$ 21.34

(1) Total includes corporate depreciation.

Depletion and depreciation expense decreased by $32.5 million to $141.7 million for Q1/2016 from $174.1 million in Q1/2015. The depletion rate of $20.55/boe for Q1/2016 decreased from $21.34/boe in Q1/2015 as the Company recognized $755.6 million of impairments on oil and gas properties in 2015 which reduced the depletable base and the depletion rate for 2016.

General and Administrative Expenses

	Three Months Ended March 31		
($ thousands except for % and per boe)	2016	2015	Change
General and administrative expenses	$ 14,169	$ 17,055	(17%)
General and administrative expenses per boe	$ 2.05	$ 2.09	(2%)

General and administrative expenses for Q1/2016 decreased 17% to $14.2 million from $17.1 million in Q1/2015. The decrease is attributable to reductions in staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending.

Share-Based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in income (loss) over the vesting period of the share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards 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 $4.4 million for Q1/2016 from $8.0 million in Q1/2015. The decrease in share-based compensation expense during Q1/2016 is a result of the lower fair value of share awards granted.

Financing and Interest

Financing and interest include interest on bank loan and long-term notes and accretion on long-term notes and asset retirement obligations.

	Three Months Ended March 31		
($ thousands except for %)	2016	2015	Change
Interest on bank loan	$ 3,611	$ 5,418	(33%)
Interest on long-term notes	23,200	21,997	5%
Accretion on long-term notes	580	377	54%
Accretion on asset retirement obligations	1,662	1,618	3%
Financing and interest	$ 29,053	$ 29,410	(1%)

Financing and interest decreased slightly to $29.1 million for Q1/2016, compared to $29.4 million in Q1/2015. Interest on bank loan of $3.6 million in Q1/2016 decreased from $5.4 million in Q1/2015 due to lower bank borrowings partially offset by a higher effective interest rate. Interest on long-term notes increased slightly to $23.2 million during Q1/2016 compared to $22.0 million in Q1/2015 as the Canadian dollar weakened during the period and approximately 81% of the long-term notes are denominated in U.S. dollars.

Foreign Exchange

Unrealized foreign exchange gains and losses are recognized with the change in the value of the long-term notes denominated in U.S. dollars. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

	Three Months Ended March 31		
($ thousands except for % and exchange rates)	2016	2015	Change
Unrealized foreign exchange (gain) loss	$ (86,801)	$101,316	(186%)
Realized foreign exchange (gain)	(542)	(4,261)	(87%)
Foreign exchange (gain) loss	$ (87,343)	$ 97,055	(190%)
CAD/USD exchange rates:			
At beginning of period	1.3840	1.1601	
At end of period	1.2971	1.2683	

The Company recorded unrealized foreign exchange gain of $86.8 million for Q1/2016. This gain related to our U.S. dollar denominated long-term notes that decreased $81.5 million during the quarter as a result of the Canadian dollar strengthening against the U.S. dollar at March 31, 2016 as compared to December 31, 2015. The realized foreign exchange gain for Q1/2016 was due to day-to-day U.S. dollar denominated transactions.

Income Taxes

	Three Months Ended March 31		
($ thousands)	2016	2015	Change
Current income tax (recovery) expense	**$ (1,442)**	$ 16,935	$ (18,377)
Deferred income tax (recovery)	**(48,122)**	(41,682)	(6,440)
Total income tax (recovery)	**$ (49,564)**	$ (24,747)	$ (24,817)

For Q1/2016, current income tax recovery of $1.4 million increased $18.4 million from an expense of $16.9 million for Q1/2015. The change primarily relates to a decrease in taxable income.

The deferred income tax recovery of $48.1 million for Q1/2016 increased $6.4 million from $41.7 million for Q1/2015. The increase is primarily the result of a decrease in the amount of tax pool claims required to shelter the decreased taxable income.

In 2014, the Canada Revenue Agency (the "CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 and 2015 income tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it is entitled to deduct the non-capital losses, that its tax filings to-date are correct, and has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a formal response to Baytex's letter. The Company expects to continue to defend the position as filed.

Net Income (Loss) and Funds From Operations

Net income for Q1/2016 totaled $0.6 million ($0.00 per basic and diluted share) compared to net loss of $175.9 million ($1.04 per basic and diluted share) in Q1/2015. Funds from operations for Q1/2016 totaled $45.6 million ($0.22 per basic and diluted share) as compared to $160.2 million ($0.95 per basic and diluted share) in Q1/2015. The components of the change in net income (loss) and funds from operations from Q1/2015 to Q1/2016 are detailed in the following table:

($ thousands)	Net income (loss)	Funds from operations
Three Months Ended March 31, 2015	$(175,916)	$160,221
Decrease in		
Operating netback	(73,098)	(73,098)
Realized financial derivatives gain	(57,208)	(57,208)
Unrealized financial derivatives loss	58,049	–
Depletion and depreciation	32,456	–
Current income tax expense	18,377	18,377
Other expenses(1)(2)	3,390	(2,647)
Increase in		
Unrealized foreign exchange gain	188,117	–
Deferred income tax (recovery)	6,440	–
Three months ended March 31, 2016	$ 607	$ 45,645

(1) For funds from operations, other expenses include general and administrative expenses, interest on bank loan and long-term notes, realized foreign exchange loss and other expenses.

(2) For net income (loss), other expenses include exploration and evaluation expenses, general and administrative expenses, other expenses, share-based compensation, financing and interest costs, realized foreign exchange loss and gain on disposition.

Dividends

In Q1/2015, we declared monthly dividends of $0.10 per share for January to March totaling $0.30 per share. The Company paid $40.0 million in cash dividends in Q1/2015, and $10.5 million of dividends declared were settled by issuing 560,000 shares under the Company's dividend reinvestment plan. In response to the prolonged low price commodity environment and in an effort to preserve liquidity, Baytex suspended the monthly dividend effective September 2015.

Other Comprehensive Income (Loss)

Other comprehensive income (loss) is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $158.7 million foreign currency translation loss for Q1/2016 is due to the strengthening of the Canadian dollar against the U.S. dollar at March 31, 2016 as compared to December 31, 2015.

Capital Expenditures

Capital expenditures for Q1/2016 and Q1/2015 are summarized as follows:

	Three Months Ended March 31					
	2016			2015		
($ thousands except for # of wells drilled)	Canada	U.S.	Total	Canada	U.S.	Total
Land	$ 862	$ –	$ 862	$ 3,456	$ 153	$ 3,609
Seismic	55	–	55	59	–	59
Drilling, completion and equipping	3,432	69,684	73,116	11,226	120,997	132,223
Facilities	506	7,146	7,652	6,531	5,007	11,538
Total exploration and development	$ 4,855	$ 76,830	$ 81,685	$ 21,272	$126,157	$147,429
Total acquisitions, net of divestitures	(9)	–	(9)	1,411	139	1,550
Total oil and natural gas expenditures	$ 4,846	$ 76,830	$ 81,676	$ 22,683	$126,296	$148,979
Wells drilled (net)	1.0	12.5	13.5	9.1	16.0	25.1

Capital spending was focused on our Eagle Ford assets with 94% of total capital being spent in the U.S. where we invested $76.8 million in Q1/2016, as compared to $126.2 million in Q1/2015. In Q1/2016, we drilled 12.5 net wells, completed 9.4 net wells and brought 10.2 net wells on stream in the Eagle Ford. We also participated in the construction of facilities resulting in $7.1 million of expenditures. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$5.6 million as compared to US$8.2 million in 2014.

Activity in Canada was significantly reduced in Q1/2016 as we drilled 1.0 net well and spent $4.8 million, as compared to 9.1 net wells and $21.3 million in Q1/2015. Despite achieving cost reductions of approximately 20% in Canada during 2015, the prevailing commodity prices during Q1/2016 did not support additional drilling on our heavy oil assets in Peace River or Lloydminster.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our capital structure and liquidity sources to ensure that our capital resources will be sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures.

We regularly review our exposure to counterparties to ensure they have the financial capacity 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.

The current commodity price environment has reduced our internally generated funds from operations. As a result, we have taken several steps to protect our liquidity, which included reducing our 2016 capital program by approximately 33% from our initial plans and working with our lending syndicate to secure our bank credit facilities. We have also shut-in low or negative margin production.

If the current commodity price environment continues, or if prices decline further, we may need to make additional changes to our capital program. A sustained low price environment could lead to a default of certain financial covenants, which could impact our ability to borrow under existing credit facilities or obtain new financing. It could also restrict our ability to pay future dividends or sell assets and may result in our debt becoming immediately due and payable. Should our internally generated funds from operations be insufficient to fund the capital expenditures required to maintain operations, we may draw additional funds from our current credit facilities or we may consider seeking additional capital in the form of debt or equity. There is also no certainty that any of the additional sources of capital would be available when required.

At March 31, 2016, net debt was $1,981.3 million, as compared to $2,049.9 million at December 31, 2015. The decrease at March 31, 2016 is primarily attributable to the decrease in our U.S. dollar denominated bank loan and long-term notes of $99 million due to the strengthening Canadian dollar. This was offset by a $34 million increase in credit facilities as capital expenditures exceeded funds from operations during the quarter.

Bank Loan

On March 31, 2016, we amended our credit facilities to provide us with increased financial flexibility. The amendments included reducing our credit facilities to US$575 million, granting our banking syndicate first priority security over our assets and restructuring our financial covenants. The amended revolving extendible secured credit facilities are comprised of a US$25 million operating loan, a US$350 million syndicated loan and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). The agreement relating to the Revolving Facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts – Credit agreements" on April 13, 2016).

The weighted average interest rate on the credit facilities for Q1/2016 was 3.5% as compared to 2.8% in Q1/2015.

Covenants

On March 31, 2016, we reached an agreement with the lending syndicate to restructure the financial covenants applicable to the Revolving Facilities. The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at March 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	Position as at March 31, 2016	March 31, 2016 to March 31, 2018	June 30, 2018 to Sept. 30, 2018	Dec. 31, 2018	Thereafter
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	0.61:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	4.82:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior secured debt" is defined as the principal amount of our bank loan and other secured obligations identified in the credit agreement. As at March 31, 2016, our Senior Secured Debt totaled $303 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest costs, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange and stock based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA is calculated based on a trailing twelve month basis and was $495 million for the twelve months ended March 31, 2016.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest excluding accretion on long-term notes and asset retirement obligations to trailing twelve month adjusted income. Financing and interest for the trailing twelve months ended March 31, 2016 was $103 million.

If we exceed or breach any of the covenants under the Revolving Facilities or our long-term notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from paying dividends to our shareholders or taking on further debt.

Long-Term Notes

Baytex has five series of senior unsecured notes outstanding that total $1.54 billion as at March 31, 2016. The senior unsecured notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond our existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of EBITDA to financing and interest costs) of 2.5:1.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These notes are redeemable at our option, in whole or in part, commencing on February 17, 2016 at specified redemption prices.

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. These notes are redeemable at our option, in whole or in part, commencing on July 19, 2017 at specified redemption prices.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "2021 Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "2024 Notes"). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at specified redemption prices.

Pursuant to the acquisition of Aurora Oil & Gas Limited ("Aurora") on June 11, 2014, we assumed all of Aurora's existing senior unsecured notes and then purchased and cancelled approximately 98% of the outstanding notes. On February 27, 2015, we redeemed one tranche of the remaining Aurora notes at a price of US$8.3 million plus accrued interest. The remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, commencing on April 1, 2016 at specified redemption prices.

Financial Instruments

As part of our normal operations, we are exposed 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 funds from operations.

A summary of the risk management contracts in place as at March 31, 2016 and the accounting treatment thereof is disclosed in note 15 to the consolidated financial statements.

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 30, 2016, we had 210,714,772 common shares and no preferred shares issued and outstanding. During Q1/2016, we issued 106,000 shares pursuant to our share-based compensation program.

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, 2016 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 228,575	$ 228,575	$ –	$ –	$ –
Bank loan[(1)(2)]	290,465	–	–	290,465	–
Long-term notes[(2)]	1,540,546	–	–	202,866	1,337,680
Interest on long-term notes	502,936	76,273	152,546	151,304	122,813
Operating leases	47,949	7,987	16,394	15,208	8,360
Processing agreements	50,004	9,010	9,521	9,043	22,430
Transportation agreements	68,211	13,193	23,107	21,903	10,008
Total	$ 2,728,686	$ 335,038	$ 201,568	$ 690,789	$1,501,291

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid 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 well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

OFF BALANCE SHEET TRANSACTIONS

Baytex does not have any financial arrangements that are excluded from the consolidated financial statements as at March 31, 2016, nor are any such arrangements outstanding as of the date of this MD&A.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Baytex is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The certificate requires Baytex to disclose in the interim MD&A any weaknesses in or changes to Baytex's internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, Baytex's internal controls over financial reporting. We confirm that no such weaknesses were identified in or changes were made to internal controls over financial reporting during the three months ended March 31, 2016.

QUARTERLY FINANCIAL INFORMATION

	2016	2015				2014		
($ thousands, except per common share amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Gross revenues	**153,598**	229,361	265,898	342,792	283,384	465,917	634,400	475,973
Net income (loss)	**607**	(412,924)	(517,856)	(26,955)	(175,916)	(361,816)	144,369	36,799
Per common share – basic	**0.00**	(1.96)	(2.49)	(0.13)	(1.04)	(2.16)	0.87	0.27
Per common share – diluted	**0.00**	(1.96)	(2.49)	(0.13)	(1.04)	(2.16)	0.86	0.27

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: our business strategies, plans and objectives; our exploration and development capital budget for 2016; our belief that the amended credit facilities provide increased financial flexibility; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our expectation for Canadian operating expenses for the remainder of 2016; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the proposed reassessment of our tax filings by the Canada Revenue Agency; the potential taxes owing and reduction of non-capital losses if the reassessment by the Canada Revenue Agency is successful; our intention to defend the proposed reassessments if issued by the Canada Revenue Agency; our view of our tax filing position; the cost to drill, complete and equip a well in the Eagle Ford; 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; 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.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and *reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; 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; 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 volatility of natural gas prices; further declines or an extended period of the currently low oil and natural gas prices; failure to comply with the covenants in our debt agreements; that our credit facilities may not provide sufficient liquidity or may not be renewed; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; risks associated with the ownership of our securities, including changes in market-based factors and the discretionary nature of dividend payments; 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 our control. 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, 2015, 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 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, 2016	December 31, 2015
ASSETS		
Current assets		
Cash	$ 452	$ 247
Trade and other receivables	77,791	98,093
Financial derivatives	80,434	106,573
	158,677	204,913
Non-current assets		
Financial derivatives	4,913	4,417
Exploration and evaluation assets (note 4)	549,673	578,969
Oil and gas properties (note 5)	4,459,057	4,674,175
Other plant and equipment	25,593	26,024
	$ 5,197,913	$ 5,488,498
LIABILITIES		
Current liabilities		
Trade and other payables	$ 228,575	$ 267,838
Financial derivatives	1,515	–
	230,090	267,838
Non-current liabilities		
Bank loan (note 6)	286,373	252,172
Long-term notes (note 7)	1,521,230	1,602,757
Asset retirement obligations (note 8)	313,930	296,002
Deferred income tax liability	582,513	655,255
Financial derivatives	2,965	–
	2,937,101	3,074,024
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 9)	4,298,956	4,296,831
Contributed surplus	6,890	4,575
Accumulated other comprehensive income	546,673	705,382
Deficit	(2,591,707)	(2,592,314)
	2,260,812	2,414,474
	$ 5,197,913	$ 5,488,498

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended March 31 2016	2015
Revenue, net of royalties		
Petroleum and natural gas sales	$ 153,598	$ 283,384
Royalties	(34,582)	(56,707)
	119,016	226,677
Expenses		
Operating	69,680	87,755
Transportation	6,775	15,949
Blending	2,359	9,673
General and administrative	14,169	17,055
Exploration and evaluation (note 4)	1,463	2,351
Depletion and depreciation	141,671	174,127
Share-based compensation (note 10)	4,440	8,004
Financing and interest (note 13)	29,053	29,410
Financial derivatives (gain) (note 15)	(14,503)	(13,662)
Foreign exchange (gain) loss (note 14)	(87,343)	97,055
Loss on disposition of oil and gas properties	22	1,854
Other expense (income)	187	(2,231)
	167,973	427,340
Net income (loss) before income taxes	(48,957)	(200,663)
Income tax (recovery) expense (note 12)		
Current income tax (recovery) expense	(1,442)	16,935
Deferred income tax (recovery)	(48,122)	(41,682)
	(49,564)	(24,747)
Net income (loss) attributable to shareholders	$ 607	$ (175,916)
Other comprehensive income (loss)		
Foreign currency translation adjustment	(158,709)	240,918
Comprehensive income (loss)	$ (158,102)	$ 65,002
Net income (loss) per common share (note 11)		
Basic	$ 0.00	$ (1.04)
Diluted	$ 0.00	$ (1.04)
Weighted average common shares (note 11)		
Basic	210,662	168,607
Diluted	211,606	168,607

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	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2014	$ 3,580,825	$ 31,067	$ 199,575	$ (1,304,690)	$ 2,506,777
Dividends to shareholders	–	–	–	(50,649)	(50,649)
Vesting of share awards	14,002	(14,002)	–	–	–
Share-based compensation	–	8,004	–	–	8,004
Issued pursuant to dividend reinvestment plan	10,545	–	–	–	10,545
Comprehensive income (loss) for the period	–	–	240,918	(175,916)	65,002
Balance at March 31, 2015	$ 3,605,372	$ 25,069	$ 440,493	$ (1,531,255)	$ 2,539,679
Balance at December 31, 2015	4,296,831	4,575	705,382	(2,592,314)	2,414,474
Vesting of share awards	2,125	(2,125)	–	–	–
Share-based compensation	–	4,440	–	–	4,440
Comprehensive income (loss) for the period	–	–	(158,709)	607	(158,102)
Balance at March 31, 2016	$ 4,298,956	$ 6,890	$ 546,673	$ (2,591,707)	$ 2,260,812

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)	2016	2015
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income (loss) for the period	$ 607	$ (175,916)
Adjustments for:		
Share-based compensation (note 10)	4,440	8,004
Unrealized foreign exchange (gain) loss (note 14)	(86,801)	101,316
Exploration and evaluation (note 4)	1,463	2,351
Depletion and depreciation	141,671	174,127
Non-cash financing and interest	2,242	1,995
Unrealized financial derivatives loss (note 15)	30,123	88,172
Loss on disposition of oil and gas properties	22	1,854
Deferred income tax (recovery)	(48,122)	(41,682)
Change in non-cash working capital	20,409	32,125
Asset retirement obligations settled (note 8)	(1,701)	(4,446)
	64,353	187,900
Financing activities		
Payment of dividends	–	(40,015)
Increase in bank loan	50,743	99,071
Tenders of long-term notes	–	(10,372)
	50,743	48,684
Investing activities		
Additions to exploration and evaluation assets (note 4)	(1,065)	(2,043)
Additions to oil and gas properties (note 5)	(80,620)	(145,386)
Property acquisitions, net of divestitures	9	(1,550)
Current income tax expense on dispositions	–	(8,181)
Additions to other plant and equipment, net of disposals	(322)	4,370
Change in non-cash working capital	(31,235)	(80,959)
	(113,233)	(233,749)
Impact of foreign currency translation on cash balances	(1,658)	985
Change in cash	205	3,820
Cash, beginning of period	247	1,142
Cash, end of period	$ 452	$ 4,962
Supplementary information		
Interest paid	$ 21,654	$ 21,590
Income taxes paid	$ 5,138	$ 8,181

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at March 31, 2016 and December 31, 2015 and for the three months ended March 31, 2016 and 2015

(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 Standard 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2015. The Company's accounting policies are unchanged compared to December 31, 2015. The use of estimates and judgments is also consistent with the December 31, 2015 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on May 2, 2016.

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. Prior period financial statement amounts have been reclassified to conform with current period presentation.

3. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the Company's geographic locations.

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada.
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the state of Texas, USA.
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended March 31	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenue, net of royalties								
Petroleum and natural gas sales	$ **45,148**	$ 132,413	$ **108,450**	$ 150,971	$ **–**	$ –	$ **153,598**	$ 283,384
Royalties	**(3,835)**	(13,419)	**(30,747)**	(43,288)	**–**	–	**(34,582)**	(56,707)
	41,313	118,994	**77,703**	107,683	**–**	–	**119,016**	226,677
Expenses								
Operating	**34,645**	60,574	**35,035**	27,181	**–**	–	**69,680**	87,755
Transportation	**6,775**	15,949	**–**	–	**–**	–	**6,775**	15,949
Blending	**2,359**	9,673	**–**	–	**–**	–	**2,359**	9,673
General and administrative	**–**	–	**–**	–	**14,169**	17,055	**14,169**	17,055
Exploration and evaluation	**1,463**	2,351	**–**	–	**–**	–	**1,463**	2,351
Depletion and depreciation	**54,785**	75,117	**86,139**	98,384	**747**	626	**141,671**	174,127
Share-based compensation	**–**	–	**–**	–	**4,440**	8,004	**4,440**	8,004
Financing and interest	**–**	–	**–**	–	**29,053**	29,410	**29,053**	29,410
Financial derivatives gain	**–**	–	**–**	–	**(14,503)**	(13,662)	**(14,503)**	(13,662)
Foreign exchange (gain) loss	**–**	–	**–**	–	**(87,343)**	97,055	**(87,343)**	97,055
Loss (gain) on disposition of oil and gas properties	**22**	2,074	**–**	(220)	**–**	–	**22**	1,854
Other expense (income)	**–**	–	**–**	–	**187**	(2,231)	**187**	(2,231)
	100,049	165,738	**121,174**	125,345	**(53,250)**	136,257	**167,973**	427,340
Net income (loss) before income taxes	**(58,736)**	(46,744)	**(43,471)**	(17,662)	**53,250**	(136,257)	**(48,957)**	(200,663)
Income tax (recovery) expense								
Current income tax (recovery) expense	**(1,442)**	16,935	**–**	–	**–**	–	**(1,442)**	16,935
Deferred income tax (recovery) expense	**(14,734)**	(15,054)	**(28,400)**	(18,261)	**(4,988)**	(8,367)	**(48,122)**	(41,682)
	(16,176)	1,881	**(28,400)**	(18,261)	**(4,988)**	(8,367)	**(49,564)**	(24,747)
Net income (loss)	$ **(42,560)**	$ (48,625)	$ **(15,071)**	$ 599	$ **58,238**	$ (127,890)	$ **607**	$ (175,916)
Total oil and natural gas capital expenditures[(1)]	$ **4,846**	$ 22,683	$ **76,830**	$ 126,296	$ **–**	$ –	$ **81,676**	$ 148,979

(1) Includes acquisitions and divestitures.

As at	March 31, 2016	December 31, 2015
Canadian assets	$ 2,015,547	$ 2,059,903
U.S. assets	3,084,283	3,304,647
Corporate assets	98,083	123,948
Total consolidated assets	$ 5,197,913	$ 5,488,498

4. EXPLORATION AND EVALUATION ASSETS

	March 31, 2016	December 31, 2015
Balance, beginning of period	$ 578,969	$ 542,040
Capital expenditures	1,065	5,642
Property acquisitions, net of divestitures	(25)	1,813
Exploration and evaluation expense	(1,463)	(8,775)
Transfer to oil and gas properties	(26)	(38,062)
Divestitures	–	(1,588)
Foreign currency translation	(28,847)	77,899
Balance, end of period	$ 549,673	$ 578,969

5. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2014	**$ 6,431,760**	**$(1,447,844)**	**$ 4,983,916**
Capital expenditures	515,397	–	515,397
Property acquisitions	551	–	551
Transferred from exploration and evaluation assets	38,062	–	38,062
Change in asset retirement obligations	10,722	–	10,722
Divestitures	(20,096)	19,449	(647)
Impairment	(755,613)	–	(755,613)
Foreign currency translation	607,885	(68,509)	539,376
Depletion	–	(657,589)	(657,589)
Balance, December 31, 2015	**$ 6,828,668**	**$(2,154,493)**	**$ 4,674,175**
Capital expenditures	80,620	–	80,620
Property acquisitions, net of divestitures	(6)	–	(6)
Transferred from exploration and evaluation assets	26	–	26
Change in asset retirement obligations	20,409	–	20,409
Foreign currency translation	(220,076)	44,833	(175,243)
Depletion	–	(140,924)	(140,924)
Balance, March 31, 2016	**$ 6,709,641**	**$(2,250,584)**	**$ 4,459,057**

6. BANK LOAN

	March 31, 2016	December 31, 2015
Bank loan – principal	$ 290,465	$ 256,749
Unamortized debt issuance costs	(4,092)	(4,577)
Bank loan	$ 286,373	$ 252,172

On March 31, 2016, Baytex amended the credit facilities with its banking syndicate to grant the banking syndicate first priority security over its assets. The amended revolving extendible secured credit facilities are comprised of a US$25 million operating loan, a US$350 million syndicated loan for Baytex and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc., (collectively, the “Revolving Facilities”).

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year period at any time). Advances (including letters of credit) under the Revolving Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex exceeds any of the covenants under the Revolving Facilities, its ability to borrow funds, increase the facilities or pay dividends to its shareholders may be restricted.

The weighted average interest rate on the credit facilities for the three months ended March 31, 2016 was 3.5% (2.8% for the three months ended March 31, 2015). Baytex is in compliance with all covenants at March 31, 2016.

7. LONG-TERM NOTES

	March 31, 2016	December 31, 2015
7.5% notes (US$6,400 – principal) due April 1, 2020	$ 8,301	$ 8,858
6.75% notes (US$150,000 – principal) due February 17, 2021	194,565	207,600
5.125% notes (US$400,000 – principal) due June 1, 2021	518,840	553,600
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	300,000	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	518,840	553,600
Total long-term notes – principal	1,540,546	1,623,658
Unamortized debt issuance costs	(19,316)	(20,901)
Total long-term notes – net of unamortized debt issuance costs	$ 1,521,230	$ 1,602,757

8. ASSET RETIREMENT OBLIGATIONS

	March 31, 2016	December 31, 2015
Balance, beginning of period	$ 296,002	$ 286,032
Liabilities incurred	1,680	4,964
Liabilities settled	(1,701)	(10,888)
Liabilities acquired	–	593
Liabilities divested	(270)	(10,578)
Accretion	1,662	6,262
Change in estimate(1)	600	33,266
Changes in discount rates and inflation rates	18,399	(17,523)
Foreign currency translation	(2,442)	3,874
Balance, end of period	$ 313,930	$ 296,002

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

9. 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, 2016, 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, 2014	**168,107**	**$ 3,580,825**
Transfer from contributed surplus on vesting and conversion of share awards	1,092	41,836
Issued for cash	36,455	632,494
Issuance costs, net of tax	–	(19,301)
Issued pursuant to dividend reinvestment plan	4,929	60,977
Balance, December 31, 2015	**210,583**	**$ 4,296,831**
Transfer from contributed surplus on vesting and conversion of share awards	106	2,125
Balance, March 31, 2016	**210,689**	**$ 4,298,956**

10. SHARE AWARD INCENTIVE PLAN

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.3% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Both awards are expensed over the vesting period.

The Company recorded compensation expense related to the share awards of $4.4 million for the three months ended March 31, 2016 (three months ended March 31, 2015 – $8.0 million).

The weighted average fair value of share awards granted during the three months ended March 31, 2016 was $2.75 per restricted and performance award (the three months ended March 31, 2015 – $17.11 per restricted and performance award).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[1]	Total number of share awards
Balance, December 31, 2014	**747**	**615**	**1,362**
Granted	615	503	1,118
Vested and converted to common shares	(432)	(382)	(814)
Forfeited	(201)	(123)	(324)
Balance, December 31, 2015	**729**	**613**	**1,342**
Granted	1,259	1,371	2,630
Vested and converted to common shares	(58)	(16)	(74)
Forfeited	(4)	(13)	(17)
Balance, March 31, 2016	**1,926**	**1,955**	**3,881**

(1) Based on underlying awards before applying performance multiplier.

11. NET INCOME (LOSS) PER SHARE

	Three Months Ended March 31					
	2016			2015		
	Net income	Common shares *(000s)*	Net income per share	Net loss	Common shares *(000s)*	Net loss per share
Net income (loss) – basic	$ 607	210,662	$ 0.00	$(175,916)	168,607	$ (1.04)
Dilutive effect of share awards	–	944	0.00	–	–	–
Net income (loss) – diluted	$ 607	211,606	$ 0.00	$(175,916)	168,607	$ (1.04)

For the three months ended March 31, 2016, 1.1 million share awards were anti-dilutive (March 31, 2015 – 2.1 million share awards).

12. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2016	2015
Net income (loss) before income taxes	$ (48,957)	$ (200,663)
Expected income taxes at the statutory rate of 27.00% (2015 – 25.47%)(1)	(13,218)	(51,109)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	1,199	2,039
Non-taxable portion of foreign exchange (gain) loss	(11,143)	13,093
Effect of change in income tax rates(1)	226	–
Effect of rate adjustments for foreign jurisdictions	(15,879)	(12,378)
Effect of change in deferred tax benefit not recognized(2)	(11,143)	23,882
Other	394	(274)
Income tax (recovery)	$ (49,564)	$ (24,747)

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Alberta (from 10% to 12%), offset by a decrease in the Texas franchise tax rate (from 1.00% to 0.75%).

(2) A deferred income tax asset has not been recognized for allowable capital losses of $107 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes ($149 million as at December 31, 2015).

In 2014, the Canada Revenue Agency (the "CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 and 2015 income tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it is entitled to deduct the non-capital losses, that its tax filings to-date are correct and formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a formal reply to Baytex's letter. The Company expects to continue to defend the position as filed.

13. FINANCING AND INTEREST

	Three Months Ended March 31	
	2016	2015
Interest on bank loan	$ 3,611	$ 5,418
Interest on long-term notes	23,200	21,997
Accretion on long-term notes	580	377
Accretion on asset retirement obligations	1,662	1,618
Financing and interest	$ 29,053	$ 29,410

14. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2016	2015
Unrealized foreign exchange (gain) loss	$ (86,801)	$ 101,316
Realized foreign exchange (gain)	(542)	(4,261)
Foreign exchange (gain) loss	$ (87,343)	$ 97,055

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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, 2016	December 31, 2015	**March 31, 2016**	December 31, 2015
U.S. dollar denominated	**US$98,833**	US$124,218	**US$1,244,957**	US$1,240,308

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	April 2016	3,000 bbl/d	US$34.80	WTI
Fixed – Sell	April 2016 to June 2016	2,000 bbl/d	US$62.50	WTI
Fixed – Sell	April 2016 to December 2016	5,000 bbl/d	US$63.79	WTI
Producer 3-way option(2)	April 2016 to December 2016	9,500 bbl/d	US$60.11/US$50/US$40	WTI
Producer 3-way option(2)	April 2016 to December 2017	2,000 bbl/d	US$60/US$50/US$40	WTI
Producer 3-way option(2)	January 2017 to December 2017	4,500 bbl/d	US$60/US$45/US$35	WTI
Basis swap	April 2016	3,000 bbl/d	WTI less US$12.82	WCS
Basis swap	April 2016 to June 2016	500 bbl/d	WTI less US$12.45	WCS
Basis swap	April 2016 to December 2016	4,500 bbl/d	WTI less US$13.27	WCS
Basis swap	July 2016 to September 2016	500 bbl/d	WTI less US$12.30	WCS
Basis swap	October 2016 to December 2016	500 bbl/d	WTI less US$13.45	WCS
Basis swap	January 2017 to December 2017	1,500 bbl/d	WTI less US$13.42	WCS
Sold call option(3)	January 2017 to December 2017	4,500 bbl/d	US$49.11	WTI
Producer 3-way option(2)(4)	July 2016 to December 2016	500 bbl/d	US$55/US$45/US$35	WTI
Producer 3-way option(2)(4)	January 2017 to December 2017	3,500 bbl/d	US$55.79/US$44.71/US$35	WTI
Sold call option(3)(4)	July 2016 to December 2016	500 bbl/d	US$48.00	WTI
Sold call option(3)(4)	January 2017 to December 2017	500 bbl/d	US$50.71	WTI

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

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in the $60/$50/$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives WTI when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.

(3) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

(4) Contracts entered subsequent to March 31, 2016.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	April 2016 to December 2016	15,000 mmBtu/d	US$2.98	NYMEX
Fixed – Sell	January 2017 to December 2017	15,000 mmBtu/d	US$2.79	NYMEX
Fixed – Sell	April 2016 to December 2016	20,000 GJ/d	$2.85	AECO
Fixed – Sell	January 2017 to December 2017	10,000 GJ/d	$2.65	AECO
Fixed – Sell(2)	January 2018 to December 2018	5,000 mmBtu/d	US$3.00	NYMEX
Fixed – Sell(2)	May 2016 to December 2016	12,500 GJ/d	$1.65	AECO

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

(2) Contracts entered subsequent to March 31, 2016.

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

	Three Months Ended March 31	
	2016	2015
Realized financial derivatives (gain)	$ (44,626)	$ (101,834)
Unrealized financial derivatives loss – commodity	30,123	90,032
Unrealized financial derivate (gain) – redemption feature on long-term notes	–	(1,860)
Financial derivatives (gain) loss	$ (14,503)	$ (13,662)

Physical Delivery Contracts

As at March 31, 2016, 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 2016 to December 2016	2,000 bbl/d	WTI less US$13.68

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

As at March 31, 2016, Baytex had committed at fixed price to deliver the volumes of raw bitumen as noted below to market on rail:

	Period	Term volume
Raw bitumen	April 2016 to June 2016	7,500 bbl/d
Raw bitumen	July 2016 to December 2016	7,400 bbl/d

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
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
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
Chairman of the Board
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
Baytex Energy Corp.
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 & 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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Caisse Centrale Desjardins
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

OFFICERS

James L. Bowzer
President and Chief Executive Officer

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets
and Public Affairs

Kendall D. Arthur
Vice President,
Lloydminster Business Unit

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

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Central Business Unit

Chad L. Kalmakoff
Vice President, Finance

Gregory A. Sawchenko
Vice President, Land

Gregory M. Zimmerman
Vice President, U.S. Business Unit

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE