Q3 REPORT 2016

SUMMARY

- Generated production of 67,167 boe/d (78% oil and NGL) in Q3/2016;
- Delivered funds from operations ("FFO") of $72.1 million ($0.34 per share) in Q3/2016;
- Reduced net debt by $79 million in Q3/2016 and by $186 million year-to-date;
- Realized an operating netback (sales price less royalties, operating and transportation expenses) in Q3/2016 of $13.91/boe ($16.95/boe including financial derivatives gain);
- Reduced operating expenses by 12% to $9.31/boe in the nine months ended September 30, 2016, as compared to $10.55/boe for same period last year;
- Maintained strong levels of financial liquidity with a Senior Secured Debt to Bank EBITDA ratio of 0.79:1.00; and
- Completed minor non-core asset sales totaling approximately $63 million.

	Three Months Ended			Nine Months Ended	
	September 30, 2016	June 30, 2016	September 30, 2015	**September 30, 2016**	September 30, 2015
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 197,648**	$ 195,733	$ 265,876	**$ 546,979**	$ 892,062
Funds from operations(1)	**72,106**	81,261	105,052	**199,012**	423,322
Per share – basic	**0.34**	0.39	0.51	**0.94**	2.18
Per share – diluted	**0.34**	0.39	0.51	**0.94**	2.18
Net income (loss)	**(39,430)**	(86,937)	(519,247)	**(125,760)**	(723,705)
Per share – basic	**(0.19)**	(0.41)	(2.50)	**(0.60)**	(3.73)
Per share – diluted	**(0.19)**	(0.41)	(2.50)	**(0.60)**	(3.73)
Exploration and development	**39,579**	35,490	126,804	**156,754**	380,243
Acquisitions, net of divestitures	**(62,752)**	(37)	(498)	**(62,798)**	2,222
Total oil and natural gas capital expenditures	**$ (23,173)**	$ 35,453	$ 126,306	**$ 93,953**	$ 382,465
Bank loan(2)	**$ 289,859**	$ 347,083	$ 208,195	**$ 289,859**	$ 208,195
Long-term notes(2)	**1,554,510**	1,544,181	1,581,002	**1,554,510**	1,581,002
Long-term debt	**1,844,369**	1,891,264	1,789,197	**1,844,369**	1,789,197
Working capital deficiency	**19,653**	51,274	160,539	**19,653**	160,539
Net debt(3)	**$ 1,864,022**	$ 1,942,538	$ 1,949,736	**$ 1,864,022**	$ 1,949,736

	Three Months Ended			Nine Months Ended	
	September 30, 2016	June 30, 2016	September 30, 2015	**September 30, 2016**	September 30, 2015
OPERATING					
Daily production					
Heavy oil (bbl/d)	**24,132**	22,423	33,639	**23,789**	36,067
Light oil and condensate (bbl/d)	**19,001**	21,894	24,712	**21,785**	26,210
NGL (bbl/d)	**9,149**	9,834	8,507	**9,695**	8,322
Total oil and NGL (bbl/d)	**52,282**	54,151	66,858	**55,269**	70,599
Natural gas (mcf/d)	**89,314**	95,281	91,869	**94,253**	91,448
Oil equivalent (boe/d @ 6:1)(4)	**67,167**	70,031	82,170	**70,978**	85,840
Benchmark prices					
WTI oil (US$/bbl)	**44.94**	45.60	46.43	**41.34**	51.00
WCS heavy oil (US$/bbl)	**31.44**	32.29	33.13	**27.66**	37.80
Edmonton par oil ($/bbl)	**54.80**	54.78	56.22	**50.14**	58.63
LLS oil (US$/bbl)	**45.82**	46.20	49.79	**41.76**	54.24
Baytex average prices (before hedging)					
Heavy oil ($/bbl)(5)	**29.79**	30.09	30.90	**23.91**	34.54
Light oil and condensate ($/bbl)	**53.25**	52.42	55.46	**47.27**	57.54
NGL ($/bbl)	**14.96**	13.28	15.35	**15.58**	16.79
Total oil and NGL ($/bbl)	**35.72**	36.07	38.00	**31.65**	42.39
Natural gas ($/mcf)	**2.95**	1.94	3.28	**2.42**	3.19
Oil equivalent ($/boe)	**31.73**	30.52	34.59	**27.86**	37.10
CAD/USD noon rate at period end	**1.3117**	1.3009	1.3394	**1.3117**	1.3394
CAD/USD average rate for period	**1.3051**	1.2885	1.3094	**1.3228**	1.2631
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**7.72**	9.04	19.50	**9.04**	24.87
Low	**4.76**	4.85	3.92	**1.57**	3.92
Close	**5.57**	7.50	4.27	**5.57**	4.27
Volume traded (thousands)	**377,435**	466,201	165,674	**1,326,946**	368,426
NYSE					
Share price (US$)					
High	**6.18**	7.14	15.51	**7.14**	20.10
Low	**3.59**	3.67	2.92	**1.08**	2.92
Close	**4.25**	5.79	3.20	**4.25**	3.20
Volume traded (thousands)	**168,984**	198,514	109,902	**521,550**	178,612
Common shares outstanding (thousands)	**211,542**	210,715	210,225	**211,542**	210,225

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 and nine months ended September 30, 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, assets held for sale, onerous contracts and liabilities related to assets held for sale)) 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 plan, strategies and objectives, including to deploy capital efficiently, emphasize cost reductions and maintain strong levels of financial liquidity; that we are well positioned to benefit from a continued oil price recovery and that our three core plays provide strong capital efficiencies; our Eagle Ford shale play, including our assessment of the performance of wells drilled in Q3/2016 and the cost to drill, complete and equip a well; our ability to continue to reduce our cost structure; our target for 2016 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings; our ability to partially reduce the volatility in our funds from operations by utilizing financial derivative contracts for commodity prices, heavy oil differentials and interest and foreign exchange rates; 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 expectations for annual average production rate and exploration and development capital expenditures for 2016; that we expect funds from operations to exceed capital expenditures in 2016; and our expectation that current activity levels in the Eagle Ford for drilling and completions will continue into 2017. 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 flow 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, assets held for sale, liabilities related to assets held for sale and onerous contracts)) 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 the credit agreement 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

Third Quarter Results

As we entered 2016, we laid out certain strategic objectives to help guide us through the commodity price downturn, which included deploying capital efficiently, continuing to emphasize cost reductions across all facets of our organization and maintaining strong levels of financial liquidity. Our third quarter results were reflective of these strategic objectives and we remain well positioned to benefit from a continued recovery in crude oil prices. We highlight below some of the results achieved to-date from the execution of these initiatives.

Operating Results

Our operating results for the third quarter were consistent with our full-year plans, with production averaging 67,167 boe/d (78% oil and NGL) in Q3/2016, as compared to 70,031 boe/d in Q2/2016. We continued to curtail our level of capital spending, focusing all development activity in the Eagle Ford. In Q3/2016, our exploration and development expenditures totaled $39.6 million, as compared to $35.5 million in Q2/2016 and $81.7 million in Q1/2016.

In the Eagle Ford, our pace of completions through the first nine months of 2016 was down approximately 21% compared to the first nine months of 2015. This reduced pace of completions, combined with the previously announced divestiture of our operated assets in the Eagle Ford, contributed to production averaging 33,552 boe/d in Q3/2016, as compared to 38,309 boe/d in Q2/2016. Year-to-date, we have participated in the drilling of 100 gross (29.5 net) wells in the Eagle Ford and commenced production from 84 gross (24.7 net) wells, as compared to the first nine months of 2015 where we participated in the drilling of 149 gross (38.4 net) wells and commenced production from 123 gross (31.3 net) wells.

We continue to advance our completion activity in the Eagle Ford with increased frac stages and proppant usage. During the third quarter, we averaged 2-3 drilling rigs and 1-2 completion crews on our lands. We participated in the drilling of 18 gross (5.7 net) wells in the Eagle Ford and commenced production from 30 gross (8.8 net) wells. Of the 30 wells that commenced production during the third quarter, 15 wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 1,350 boe/d.

In Canada, we reinitiated production during the second quarter from heavy oil wells that were shut-in earlier this year. The full benefit of bringing these shut-in volumes back online was realized during the third quarter, which led to a 6% increase in Canadian production to 33,615 boe/d, as compared to 31,722 boe/d in Q2/2016.

Cost Reductions

We continue to have success in reducing our cost structure while maintaining safety and efficiency in our operations.

Costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$5.2 million, as compared to US$8.2 million in late 2014. The prevailing commodity price environment has not supported drilling on our Canadian assets in 2016. However, we continue to actively build on the 20% cost reductions achieved in 2015 and strengthen the size and quality of our prospect inventory.

Operating expenses have been reduced by 12% to $9.31/boe in the first nine months of 2016, as compared to $10.55/boe for the same period in 2015. These cost reductions reflect a combination of a lower overall cost structure in Canada and our lower cost Eagle Ford assets representing a larger percentage of our total production. Transportation expenses are also down, averaging $1.05/boe through the first nine months of 2016, as compared to $1.81/boe for the same period in 2015.

General and administrative expenses for the three and nine months ended September 30, 2016 of $12.1 million and $38.5 million, respectively, decreased from $14.0 million and $46.6 million for the same periods in 2015. The decrease is attributable to reductions in staffing levels combined with cost saving initiatives.

Financial Liquidity

We have targeted our capital expenditures to approximate our funds from operations to minimize additional bank borrowings. In Q3/2016, our funds from operations totaled $72.1 million, as compared to capital expenditures of $39.6 million, and in the first nine months of 2016, our funds from operations totaled $199.0 million, as compared to capital expenditures of $156.8 million.

Our net debt (bank loan, long-term notes and working capital deficiency) has decreased to $1.86 billion at September 30, 2016 from $2.05 billion at December 31, 2015.

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 revolving credit facilities, which currently mature in June 2019, are not borrowing base facilities and do not require annual or semi-annual reviews. Our Senior Secured Debt to Bank EBITDA ratio as at September 30, 2016 was 0.79:1.00 (maximum permitted ratio of 5.00:1.00) and our interest coverage ratio was 3.62:1.00 (minimum required ratio of 1.25:1.00).

Operating Netback

During the third quarter, our operating netback was largely unchanged as compared to Q2/2016. In Q3/2016, the price for West Texas Intermediate light oil ("WTI") averaged US$44.94/bbl, as compared to US$45.60/bbl in Q2/2016, while the discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$13.50/bbl in Q3/2016, as compared to US$13.31/bbl in Q2/2016.

We generated an operating netback in Q3/2016 of $13.91/boe ($16.95/boe including financial derivatives gain), as compared to $14.39/boe ($18.13/boe including financial derivatives gain) in Q2/2016. The Eagle Ford generated an operating netback of $20.24/boe during Q3/2016 while our Canadian operations generated an operating netback of $7.59/boe.

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

	Three Months Ended September 30					
	2016			2015		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	33,615	33,552	67,167	43,229	38,941	82,170
Oil and natural gas revenues	$ 26.52	$ 36.95	$ 31.73	$ 29.06	$ 40.72	$ 34.59
Less:						
Royalties	3.85	10.89	7.37	3.88	11.74	7.61
Operating expenses	12.32	5.82	9.07	12.31	7.97	10.25
Transportation expenses	2.76	–	1.38	2.88	–	1.52
Operating netback	$ 7.59	$ 20.24	$ 13.91	$ 9.99	$ 21.01	$ 15.21
Realized financial derivatives gain	–	–	3.04	–	–	3.33
Operating netback after financial derivatives gain	$ 7.59	$ 20.24	$ 16.95	$ 9.99	$ 21.01	$ 18.54

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 $18.8 million in Q3/2016 due to crude oil and natural gas prices being at levels below those in our financial derivative contracts.

For the fourth quarter of 2016, we have entered into hedges on approximately 45% of our net WTI exposure with 15% fixed at US$63.79/bbl and 30% hedged utilizing a 3-way option structure that provide us with downside price protection at approximately US$50/bbl and upside participation to approximately US$60/bbl. We have also entered into hedges on approximately 41% of our net WCS differential exposure and 65% of our net natural gas exposure.

For 2017, we have entered into hedges on approximately 44% of our net WTI exposure utilizing a 3-way option structure that provide us with downside price protection at approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 24% of our net WCS differential exposure and 49% of our net natural gas exposure.

A complete listing of our financial derivative contracts can be found in Note 15 to our Q3/2016 financial statements.

Disposition Activity

On July 27, 2016, we closed the previously announced disposition of our operated assets in the Eagle Ford for net proceeds of $54.6 million. At the time of disposition, these assets were producing approximately 1,000 boe/d and included reserves of approximately 1.26 million boe on a proved plus probable basis (as evaluated by Ryder Scott Company, L.P. at December 31, 2015). In addition, we have disposed of an additional 650 boe/d of certain non-core assets in Canada. We do not anticipate any further asset sales at this time.

Guidance

We are revising upward our full year 2016 production guidance range to 69,000 to 70,000 boe/d (previously 67,000 to 69,000 boe/d). We anticipate our full year 2016 exploration and development capital expenditures will be toward the high end of our guidance of $200 to $225 million. At this level of spending and based on the forward strip for crude oil and natural gas, we expect our funds from operations to exceed capital expenditures in 2016.

In the Eagle Ford, we are currently running 4 drilling rigs and 2 completion crews on our lands. We expect this level of activity to continue into 2017. We have also commenced preliminary work in advance of a 2017 development program in Canada, including lease construction and surveying.

We are in the process of setting our 2017 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

Conclusion

Our operating results for the third quarter were consistent with our expectations. For the second consecutive quarter our funds from operations exceeded capital expenditures resulting in a reduction in net debt. Production in Canada increased 6% over the second quarter as we received the full benefit of restored production from previously shut-in heavy oil wells, while production in the Eagle Ford was lower reflective of a reduced pace of development and our operated asset sale. We remain committed to deploying capital efficiently, reducing costs in all facets of our business and maintaining strong levels of financial liquidity. We are well positioned to benefit from a rising oil price environment with strong capital efficiencies across our three core resource plays.

We look forward to executing our plans 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
Chief Executive Officer
November 2, 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 and nine months ended September 30, 2016. This information is provided as of November 1, 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 results for the nine months ended September 30, 2016 ("YTD 2016") have been compared with the results for the nine months ended September 30, 2015 ("YTD 2015") and the results for the three months ended September 30, 2016 ("Q3/2016") have been compared with the results for the three months ended September 30, 2015 ("Q3/2015"). This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and nine months ended September 30, 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 and through the U.S. Securities and Exchange Commission at www.sec.gov. 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

We consider 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 September 30		Nine Months Ended September 30	
($ thousands)	**2016**	2015	**2016**	2015
Cash flow from operating activities	**$ 88,887**	$ 148,911	**$ 208,201**	$ 474,659
Change in non-cash working capital	**(17,180)**	(46,132)	**(11,997)**	(61,216)
Asset retirement expenditures	**399**	2,273	**2,808**	9,879
Funds from operations	**$ 72,106**	$ 105,052	**$ 199,012**	$ 423,322

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 September 30, 2016 and December 31, 2015.

($ thousands)	September 30, 2016	December 31, 2015
Bank loan[1]	$ 289,859	$ 256,749
Long-term notes[1]	1,554,510	1,623,658
Working capital deficiency[2]	19,653	169,498
Net debt	$ 1,864,022	$ 2,049,905

(1) Principal amount of instruments expressed in Canadian dollars.

(2) Working capital is current assets less current liabilities (excluding current financial derivatives, assets held for sale, onerous contracts and liabilities related to assets held for sale).

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) "a GAAP measure" to Bank EBITDA "a non-GAAP measure".

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2016	2015	2016	2015
Net income (loss)	$ (39,430)	$ (519,247)	$ (125,760)	$ (723,705)
Plus:				
Financing and interest	28,409	27,542	85,350	83,724
Unrealized foreign exchange loss (gain)	11,361	89,215	(71,891)	172,182
Unrealized financial derivatives (gain) loss	(5,639)	(37,234)	105,048	92,677
Current income tax (recovery) expense	(4,261)	178	(7,987)	16,560
Deferred income tax (recovery)	(14,589)	(91,858)	(109,494)	(145,853)
Depletion and depreciation	118,231	162,503	381,842	498,106
Impairment	26,559	493,227	26,559	493,227
Disposition of oil and gas properties (gain) loss	(43,453)	(305)	(43,431)	1,525
Non-cash items[1]	16,491	6,603	28,223	28,969
Bank EBITDA	$ 93,679	$ 130,624	$ 268,459	$ 517,412

(1) Non-cash items include share-based compensation, exploration and evaluation expense and non-cash other expense.

THIRD QUARTER HIGHLIGHTS

In Q3/2016, we continued to prudently manage our capital program to mitigate any increase to our debt. This is evidenced by our FFO of $72.1 million in Q3/2016 which exceeded capital expenditures of $39.6 million during the quarter. We also sold our operated assets in the Eagle Ford along with some non-core Canadian assets for proceeds of $63 million. Proceeds from the asset sales were applied to outstanding bank indebtedness.

Production averaged 67,167 boe/d during Q3/2016, a decrease of 4% from Q2/2016. This decrease is consistent with expectations and is a result of reduced capital spending combined with asset dispositions. Canadian production averaged 33,615 boe/d for Q3/2016, an increase of 6% from Q2/2016. This increase is attributable to previously shut-in production that was brought back on with the improvement in commodity prices during the second half of Q2/2016 and remained operating during the entire third quarter. U.S. production averaged 33,552 boe/d for Q3/2016 which was down approximately 12% from 38,309 boe/d in Q2/2016. This decrease in the U.S. was due to a reduced pace of development and the sale of approximately 1,000 boe/d associated with our operated lands. YTD 2016 production averaged 70,978 boe/d during 2016, down 17% as compared to YTD 2015. The decrease from 2015 is mainly attributable to reduced capital activity as evidenced by the limited amount of capital spending in Canada over the last 21 months combined with reduced drilling and completion activity in the Eagle Ford. YTD 2016 production has also been impacted by 7,500 boe/d that was shut in during part of the first half of 2016 due to low commodity prices.

Oil prices stabilized during Q3/2016 and WTI averaged US$44.94/bbl down only slightly from US$45.60/bbl in Q2/2016 and US$46.43/bbl in Q3/2015. Our realized light oil and condensate price also remained relatively consistent and averaged $53.25/bbl in Q3/2016 compared to $52.42/bbl in Q2/2016 and $55.46/bbl in Q3/2015. Heavy oil differentials were also stable, averaging US$13.50/bbl in Q3/2016 compared to US$13.31/bbl in Q2/2016 and US$13.30/bbl in Q3/2015. Natural gas prices improved substantially with the NYMEX natural gas price averaging US$2.81/mmbtu in Q3/2016 compared to US$1.95/mmbtu in Q2/2016. With stable oil pricing and increased natural gas pricing, our realized sales price increased slightly to $31.73/boe in Q3/2016 from $30.52/boe in Q2/2016. YTD 2016 commodity prices have been substantially weaker than YTD 2015. WTI prices averaged US$41.34/bbl in YTD 2016 compared to US$51.00/bbl in YTD 2015. WCS heavy oil prices decreased 27% from US$37.80/bbl in YTD 2015 to US$27.66/bbl in YTD 2016. Natural gas prices have declined 18% with the NYMEX price of US$2.29/mmbtu in YTD 2016 compared to US$2.80/mmbtu in YTD 2015. With the decline in prices across all commodities, our realized sales price has decreased 25% in YTD 2016 from YTD 2015.

We generated FFO of $72.1 million ($0.34 per basic and diluted share) during Q3/2016 compared to $81.3 million ($0.39 per basic and diluted share) in Q2/2016. The 11% decrease in FFO is mainly attributed to lower production, lower realized hedging gains and slightly higher royalties and operating expenses. FFO for YTD 2016 of $199.0 million is down 53% from YTD 2015 and is directly attributable to lower commodity prices, lower production volumes in Canada and lower realized hedging gains.

Capital activity in the current quarter remained low with capital expenditures totaling $39.6 million, up slightly from $35.5 million in Q2/2016 and down from $126.8 million in Q3/2015. Capital spending in the Eagle Ford totaled $33.5 million in Q3/2016 compared to $93.3 million in Q3/2015. In Canada, there was limited activity with capital spending of $6.1 million in Q3/2016 compared to $33.5 million in Q3/2015.

With reduced capital spending and proceeds from asset dispositions, our net debt decreased to $1.86 billion at September 30, 2016 from $2.05 billion at December 31, 2015. We are in compliance with all of our financial covenants with approximately $465 million in undrawn credit capacity at September 30, 2016.

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 September 30					
	2016			2015		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	24,132	–	24,132	33,639	–	33,639
Light oil and condensate	1,321	17,680	19,001	1,729	22,983	24,712
NGL	1,188	7,961	9,149	985	7,522	8,507
Total liquids (bbl/d)	26,641	25,641	52,282	36,353	30,505	66,858
Natural gas (mcf/d)	41,846	47,468	89,314	41,256	50,613	91,869
Total production (boe/d)	33,615	33,552	67,167	43,229	38,941	82,170
Production Mix						
Heavy oil	71%	–%	35%	77%	–%	40%
Light oil and condensate	4%	53%	29%	4%	59%	30%
NGL	4%	23%	14%	3%	19%	11%
Natural gas	21%	24%	22%	16%	22%	19%

	Nine Months Ended September 30					
	2016			2015		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	23,789	–	23,789	36,067	–	36,067
Light oil and condensate	1,449	20,336	21,785	1,905	24,305	26,210
NGL	1,263	8,432	9,695	1,102	7,220	8,322
Total liquids (bbl/d)	26,501	28,768	55,269	39,074	31,525	70,599
Natural gas (mcf/d)	41,093	53,160	94,253	41,514	49,934	91,448
Total production (boe/d)	33,350	37,628	70,978	45,993	39,847	85,840
Production Mix						
Heavy oil	71%	–%	34%	79%	–%	41%
Light oil and condensate	4%	54%	31%	4%	62%	31%
NGL	4%	22%	13%	2%	18%	10%
Natural gas	21%	24%	22%	15%	20%	18%

Production for Q3/2016 averaged 67,167 boe/d representing an 18% decrease from Q3/2015. This decrease is consistent with expectations and is a result of reduced capital spending. U.S. production averaged 33,552 boe/d in Q3/2016, a 14% decrease from Q3/2015. Production decreased due to the sale of approximately 1,000 boe/d of operated production in the Eagle Ford in Q3/2016 and reduced capital spending. In Canada, production decreased 22% to 33,615 boe/d in Q3 2016 compared to Q3/2015. This decrease is due to natural declines as there has been minimal capital spending in Canada over the last 21 months.

Production for YTD 2016 averaged 70,978 boe/d, a 17% decrease from YTD 2015. U.S. production averaged 37,628 boe/d in YTD 2016, a 6% decrease from YTD 2015 as a result of decreased capital investment combined with the sale of 1,000 boe/d of operated production in the Eagle Ford. Canadian production of 33,350 boe/d decreased 27%, or 12,643 boe/d, from YTD 2015 due to minimal capital investment along with 7,500 boe/d of low or negative production that was shut-in earlier in 2016. Production from the shut-in wells was reinitiated during Q2/2016, with the full benefit being realized in Q3/2016. The shut-in volumes reduced YTD 2016 average production by approximately 3,200 boe/d.

Commodity Prices

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

Crude Oil

For Q3/2016, the WTI oil prompt averaged US$44.94/bbl, a 3% decrease from the average WTI price of US$46.43/bbl in Q3/2015. For YTD 2016, the WTI oil prompt averaged US$41.34/bbl, a 19% decrease from the average WTI price of US$51.00/bbl for YTD 2015. WTI continues to be challenged during 2016 as the global over supply of crude oil combined with increased inventory levels weighs on the price.

The discount for Canadian heavy oil is measured by the Western Canadian Select ("WCS") price differential to WTI. For the three and nine months ended September 30, 2016, the WCS heavy oil differential averaged US$13.50/bbl and US$13.68/bbl, respectively, compared to US$13.30/bbl and US$13.20/bbl for the same periods in 2015. Over the past year, increased pipeline capacity from Canada to the U.S. Gulf Coast combined with lower overall production levels has helped to stabilize the WCS heavy oil differential over the periods.

Natural Gas

Natural gas prices have been driven lower during 2016 compared to 2015 mainly due to increased production levels resulting in excess supply. For Q3/2016 and YTD 2016, the AECO natural gas prices averaged $2.20/mcf and $1.85/mcf, respectively, a decrease of $0.50/mcf and $0.92/mcf compared to the same periods in 2015. For Q3/2016, the NYMEX natural gas price averaged US$2.81/mmbtu, which increased by US$0.04/mmbtu compared to Q3/2015 due to warmer weather conditions in the summer of 2016 which increased power demand resulting in slightly improved prices. For YTD 2016, the NYMEX natural gas price averaged US$2.29/mmbtu, a decrease of US$0.51/mmbtu compared YTD 2015.

The following table compares selected benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30			Nine Months Ended September 30		
	2016	2015	Change	2016	2015	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**44.94**	46.43	(3%)	**41.34**	51.00	(19%)
WTI oil (CAD$/bbl)	**58.66**	60.80	(4%)	**54.68**	64.42	(15%)
WCS heavy oil (US$/bbl)[2]	**31.44**	33.13	(5%)	**27.66**	37.80	(27%)
WCS heavy oil (CAD$/bbl)	**41.03**	43.38	(5%)	**36.59**	47.75	(23%)
LLS oil (US$/bbl)[3]	**45.82**	49.79	(8%)	**41.76**	54.24	(23%)
LLS oil (CAD$/bbl)	**59.80**	65.20	(8%)	**55.24**	68.51	(19%)
CAD/USD average exchange rate	**1.3051**	1.3094	–%	**1.3228**	1.2631	5%
Edmonton par oil ($/bbl)	**54.80**	56.22	(3%)	**50.14**	58.63	(14%)
AECO natural gas price ($/mcf)[4]	**2.20**	2.70	(18%)	**1.85**	2.77	(33%)
NYMEX natural gas price (US$/mmbtu)[5]	**2.81**	2.77	2%	**2.29**	2.80	(18%)

(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 September 30					
	2016			2015		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 29.79**	**$ –**	**$ 29.79**	$ 30.90	$ –	$ 30.90
Light oil and condensate ($/bbl)	**48.51**	**53.60**	**53.25**	51.86	55.73	55.46
NGL ($/bbl)	**17.09**	**14.64**	**14.96**	15.05	15.39	15.35
Natural gas ($/mcf)	**2.11**	**3.70**	**2.95**	2.72	3.74	3.28
Weighted average ($/boe)[2]	**$ 26.52**	**$ 36.95**	**$ 31.73**	$ 29.06	$ 40.72	$ 34.59

	Nine Months Ended September 30					
	2016			2015		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 23.91**	**$ –**	**$ 23.91**	$ 34.54	$ –	$ 34.54
Light oil and condensate ($/bbl)	**43.56**	**47.53**	**47.27**	53.84	57.83	57.54
NGL ($/bbl)	**17.52**	**15.28**	**15.58**	21.06	16.14	16.79
Natural gas ($/mcf)	**1.79**	**2.91**	**2.42**	2.67	3.62	3.19
Weighted average ($/boe)[2]	**$ 21.81**	**$ 33.22**	**$ 27.86**	$ 32.23	$ 42.73	$ 37.10

(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 Q3/2016 was $53.60/bbl, down 4% from $55.73/bbl in Q3/2015, which is slightly less than the 8% decrease in the LLS benchmark (expressed in Canadian dollars). U.S. light oil and condensate pricing for YTD 2016 was $47.53/bbl, down 18% from $57.83/bbl in YTD 2015 which coincides to a

19% decrease in the LLS benchmark (expressed in Canadian dollars) over the same period. Reduced supply along with increased pipeline capacity have tightened the pricing differential between our realized U.S. light oil and condensate pricing to LLS during 2016 compared to 2015.

During Q3/2016, our Canadian average sales price for light oil and condensate was $48.51/bbl, down 6% from $51.86/bbl in Q3/2015, as compared to a 3% decrease in the benchmark Edmonton par price. Canadian light oil and condensate pricing was $43.56/bbl for YTD 2016 compared to $53.84/bbl for YTD 2015, a 19% decrease compared to a 14% decrease in the benchmark Edmonton par price. Our Canadian realized price decreased slightly more than the benchmark when comparing 2016 to 2015 as a higher percentage of our Canadian light oil production in 2016 is comprised of medium grade crude which has a higher discount to the benchmark price.

Our realized heavy oil price for Q3/2016 was $29.79/bbl, a $1.11/bbl decrease from Q3/2015. YTD 2016, our realized heavy oil price was $23.91/bbl, a $10.63/bbl decrease from YTD 2015. The decrease in our realized heavy oil price during 2016 generally coincides with the decrease in the WCS benchmark price (expressed in Canadian dollars) which decreased from 2015 by $2.35/bbl for Q3/2016 and by $11.16/bbl for YTD 2016 as our heavy oil is generally sold at a fixed dollar differential to the benchmark. Our realized price decreased slightly less than the benchmark for both comparative periods as the volumes that were shut-in during 2016 have a higher discount to the benchmark price resulting in better price realizations in 2016.

Our Canadian average realized natural gas price for Q3/2016 was $2.11/mcf, down 22% from Q3/2015. YTD 2016 our average realized natural gas price was $1.79/mcf down 33% from the same period in 2015. The decrease in our realized prices during 2016 was consistent with the decrease in the AECO benchmarks of 18% and 33%, respectively, from the same periods in 2015.

Our U.S. average realized natural gas price for Q3/2016 was $3.70/mcf relatively unchanged from $3.74/mcf in Q3/2015 and comparable to the 2% change in the NYMEX benchmark over the same period. YTD 2016 our realized natural gas price was $2.91/mcf down 20% from the same period in 2015 which is consistent with the decrease in the NYMEX benchmark of 18% over the same period.

Our realized NGL price was $14.96/bbl or 26% of WTI (expressed in Canadian dollars) in Q3/2016 compared to $15.35/bbl or 25% of WTI (expressed in Canadian dollars) in Q3/2015. For YTD 2016, our realized NGL price was 28% of WTI (expressed in Canadian dollars) which is slightly higher than 26% of WTI in YTD 2015. The change in percentage of WTI can vary from period to period based on the product mix.

Gross Revenues

	Three Months Ended September 30					
	2016			2015		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 66,129	$ –	$ 66,129	$ 95,634	$ –	$ 95,634
Light oil and condensate	5,896	87,184	93,080	8,252	117,840	126,092
NGL	1,867	10,721	12,588	1,365	10,647	12,012
Total liquids revenue	73,892	97,905	171,797	105,251	128,487	233,738
Natural gas revenue	8,123	16,141	24,264	10,308	17,405	27,713
Total oil and natural gas revenue	82,015	114,046	196,061	115,559	145,892	261,451
Heavy oil blending revenue	1,587	–	1,587	4,425	–	4,425
Total petroleum and natural gas revenues	$ 83,602	$114,046	$197,648	$119,984	$145,892	$265,876

	Nine Months Ended September 30					
	2016			2015		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$155,832	$ –	$155,832	$340,116	$ –	$340,116
Light oil and condensate	17,290	264,851	282,141	28,004	383,683	411,687
NGL	6,063	35,314	41,377	6,337	31,814	38,151
Total liquids revenue	179,185	300,165	479,350	374,457	415,497	789,954
Natural gas revenue	20,108	42,368	62,476	30,230	49,317	79,547
Total oil and natural gas revenue	199,293	342,533	541,826	404,687	464,814	869,501
Heavy oil blending revenue	5,153	–	5,153	22,561	–	22,561
Total petroleum and natural gas revenues	$204,446	$342,533	$546,979	$427,248	$464,814	$892,062

Total oil and natural gas revenues for Q3/2016 of $196.1 million decreased $65.4 million from Q3/2015 with lower commodity prices contributing $17.7 million of the decrease and the remaining $47.7 million from lower production volumes. Oil and natural gas revenues of $114.0 million in the U.S. decreased $31.8 million from Q3/2015 with lower production volumes and lower pricing on all products.

In Canada, oil and natural gas revenues for Q3/2016 totaled $82.0 million, a $33.5 million decrease compared to Q3/2015 due to lower production volumes and lower realized prices.

Total oil and natural gas revenues for YTD 2016 of $541.8 million decreased $327.7 million from YTD 2015 with lower commodity prices contributing $179.8 million of the decrease and the remaining $147.9 million from lower production volumes. Oil and natural gas revenues of $342.5 million in the U.S. decreased $122.3 million from YTD 2015 mainly due to a decrease in realized prices on all products. In Canada, oil and natural gas revenues for YTD 2016 totaled $199.3 million, a $205.4 million decrease compared to YTD 2015 due to lower realized prices and lower production volumes.

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. Heavy oil blending revenue of $1.6 million and $5.2 million for the three and nine months ended September 30, 2016, respectively, decreased $2.8 million and $17.4 million compared to the same periods in 2015. Heavy oil blending revenue decreased in 2016 as we sold less diluent due to the decrease in heavy oil production in Canada.

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 the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30					
	2016			2015		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 11,918	$ 33,613	$ 45,531	$ 15,445	$ 42,058	$ 57,503
Average royalty rate(1)	14.5%	29.5%	23.2%	13.4%	28.8%	22.0%
Royalty rate per boe	$ 3.85	$ 10.89	$ 7.37	$ 3.88	$ 11.74	$ 7.61

	Nine Months Ended September 30					
	2016			2015		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 23,673	$ 98,826	$122,499	$ 57,122	$134,974	$192,096
Average royalty rate(1)	11.9%	28.9%	22.6%	14.1%	29.0%	22.1%
Royalty rate per boe	$ 2.59	$ 9.59	$ 6.30	$ 4.55	$ 12.41	$ 8.20

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

Total royalties for Q3/2016 of $45.5 million decreased 21%, or $12.0 million, from Q3/2015, due to the decline in gross revenues. The overall royalty rate in Q3/2016 of 23.2% was slightly higher than 22.0% in Q3/2015 as the royalty rate in Canada increased as we reflected a $1.4 million increase to royalties on a heavy oil project that had certain capital deductions removed relating to a prior period. The royalty percentage on our U.S. assets does not vary with price and as a result the U.S. royalty rate in Q3/2016 of 29.5% has remained fairly consistent with the Q3/2015 rate of 28.8%.

Total royalties for YTD 2016 of $122.5 million decreased 36%, or $69.6 million, from YTD 2015, due to the decline in gross revenues. The overall royalty rate in YTD 2016 of 22.6% was consistent with 22.1% in YTD 2015. The Canadian royalty rate decreased, but a higher proportion of our revenue came from the U.S. in YTD 2016, which has higher royalty rates, offsetting the impact of the decrease in the Canadian rate on the overall royalty rate. Canadian royalties decreased to 11.9% of revenue for YTD 2016, compared to 14.1% of revenue in YTD 2015 due to lower commodity prices. The royalty percentage on our U.S. assets does not vary with price and as a result the YTD 2016 U.S. royalty rate of 28.9% has remained consistent with the YTD 2015 rate of 29.0% and overall royalties have decreased with the decrease in gross revenues.

Operating Expenses

	Three Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Operating expenses	$ 38,115	$ 17,958	$ 56,073	$ 48,946	$ 28,544	$ 77,490
Operating expenses per boe	$ 12.32	$ 5.82	$ 9.07	$ 12.31	$ 7.97	$ 10.25

	Nine Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Operating expenses	$ 104,040	$ 76,988	$ 181,028	$ 164,860	$ 82,465	$ 247,325
Operating expenses per boe	$ 11.39	$ 7.47	$ 9.31	$ 13.13	$ 7.58	$ 10.55

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

Operating expenses of $56.1 million and $181.0 million for Q3/2016 and YTD 2016, respectively, decreased by $21.4 million and $66.3 million compared to the same periods in 2015. Overall operating costs are down as production has decreased in 2016 compared to 2015. Operating expenses are also down on a unit of production basis with operating costs decreasing to $9.07/boe and $9.31/boe for Q3/2016 and YTD 2016, respectively, compared to $10.25/boe and $10.55/boe for the same periods in 2015. The lower cost Eagle Ford assets comprise a larger proportion of our overall volumes which has helped reduce our overall operating costs per boe. In Canada, the impacts of our cost savings initiatives along with the benefit of shutting-in higher cost properties resulted in lower operating expenses per unit of production for YTD 2016 compared to YTD 2015. For Q3/2016, operating expenses per unit of production in Canada were consistent with Q3/2015 as shut-in volumes were brought back on and cost savings initiatives mitigated the impact of fixed costs on lower production volumes.

U.S. operating expenses of $18.0 million for Q3/2016 decreased $10.6 million compared to Q3/2015 with the decrease in production and a lower per unit cost structure. Operating expenses on a per unit of production basis decreased to $5.82/boe in Q3/2016 compared to $7.97/boe in Q3/2015 reflecting the disposition of higher cost operated assets in the Eagle Ford in Q3/2016, a lower overall cost structure and prior period adjustments of approximately $2.0 million or $0.63/boe. On a unit of production basis, YTD 2016 operating expenses remained relatively unchanged at $7.47/boe compared to $7.58/boe in YTD 2015 as the Canadian dollar has weakened in YTD 2016 which has mitigated the impact of the lower cost operating structure.

Canadian operating expenses of $38.1 million and $104.0 million for Q3/2016 and YTD 2016, respectively, decreased $10.8 million and $60.8 million compared to the same periods in 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 $12.32/boe and $11.39/boe for Q3/2016 and YTD 2016, respectively, compared to $12.31/boe and $13.13/boe for the same periods in 2015 reflecting the cost savings initiatives during 2016 and the impact of higher cost production being shut-in for part of YTD 2016.

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 the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.[(1)]	Total	Canada	U.S.[(1)]	Total
Transportation expenses	$ 8,533	$ –	$ 8,533	$ 11,456	$ –	$ 11,456
Transportation expense per boe	$ 2.76	$ –	$ 1.38	$ 2.88	$ –	$ 1.52

	Nine Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.[(1)]	Total	Canada	U.S.[(1)]	Total
Transportation expenses	$ 20,454	$ –	$ 20,454	$ 42,331	$ –	$ 42,331
Transportation expense per boe	$ 2.24	$ –	$ 1.05	$ 3.37	$ –	$ 1.81

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

Transportation expenses for Q3/2016 and YTD 2016 totaled $8.5 million and $20.5 million, respectively, a decrease of 26% and 52% from the same periods in 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, YTD 2016 costs have decreased with the use of lower cost internal trucking and due to shut-in volumes which were generally subject to higher transportation charges. Q3/2016 transportation costs of $1.38/boe were slightly lower than $1.52/boe in Q3/2015 but higher than Q1/2016 and Q2/2016 which averaged $0.90/boe. Costs increased over the first half of 2016 as we brought the shut-in volumes back online and from a third-party pipeline service interruption which resulted in approximately 3,000 bbl/d of additional trucked volumes in Q3/2016. Despite these increases, Q3/2016 per unit costs are lower than Q3/2015 with increased use of lower cost internal trucking and minimizing trucking distances.

Blending Expenses

Blending expenses for the Q3/2016 and YTD 2016 of $1.6 million and $5.2 million, respectively, have decreased compared to $4.4 million and $22.6 million for the same periods of 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 the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2016**	2015	Change	**2016**	2015	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 17,387**	$ 36,628	$ (19,241)	**$ 77,657**	$ 193,439	$ (115,782)
Natural gas	**1,363**	577	786	**9,535**	6,614	2,921
Foreign currency	**–**	(12,053)	12,053	**–**	(32,995)	32,995
Total	**$ 18,750**	$ 25,152	$ (6,402)	**$ 87,192**	$ 167,058	$ (79,866)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 3,982**	$ 36,253	$ (32,271)	**$ (95,544)**	$ (92,871)	$ (2,673)
Natural gas	**1,657**	3,510	(1,853)	**(9,504)**	(1,137)	(8,367)
Foreign currency	**–**	3,249	(3,249)	**–**	1,829	(1,829)
Interest and financing(1)	**–**	(5,778)	5,778	**–**	(498)	498
Total	**$ 5,639**	$ 37,234	$ (31,595)	**$ (105,048)**	$ (92,677)	$ (12,371)
Total financial derivatives gain (loss)						
Crude oil	**$ 21,369**	$ 72,881	$ (51,512)	**$ (17,887)**	$ 100,568	$ (118,455)
Natural gas	**3,020**	4,087	(1,067)	**31**	5,477	(5,446)
Foreign currency	**–**	(8,804)	8,804	**–**	(31,166)	31,166
Interest and financing	**–**	(5,778)	5,778	**–**	(498)	498
Total	**$ 24,389**	$ 62,386	$ (37,997)	**$ (17,856)**	$ 74,381	$ (92,237)

(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 $18.8 million and $87.2 million for Q3/2016 and YTD 2016, respectively, relate mainly to crude oil prices being at levels below those set in our fixed price contracts.

The unrealized financial derivatives gain of $5.6 million for Q3/2016 is due to lower commodity futures price at September 30, 2016 as compared to June 30, 2016. The unrealized financial derivatives loss of $105.0 million for

YTD 2016 is due to the realization, or reversal, of previous unrealized gains recorded at December 31, 2015 and from the increase in WTI futures price at September 30, 2016 as compared to December 31, 2015.

A summary of the financial derivative contracts in place as at September 30, 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 September 30					
	2016			2015		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	33,615	33,552	67,167	43,229	38,941	82,170
Operating netback:						
Oil and natural gas revenues	$ 26.52	$ 36.95	$ 31.73	$ 29.06	$ 40.72	$ 34.59
Less:						
Royalties	3.85	10.89	7.37	3.88	11.74	7.61
Operating expenses	12.32	5.82	9.07	12.31	7.97	10.25
Transportation expenses	2.76	–	1.38	2.88	–	1.52
Operating netback	$ 7.59	$ 20.24	$ 13.91	$ 9.99	$ 21.01	$ 15.21
Realized financial derivatives gain	–	–	3.04	–	–	3.33
Operating netback after financial derivatives	$ 7.59	$ 20.24	$ 16.95	$ 9.99	$ 21.01	$ 18.54

	Nine Months Ended September 30					
	2016			2015		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	33,350	37,628	70,978	45,993	39,847	85,840
Operating netback:						
Oil and natural gas revenues	$ 21.81	$ 33.22	$ 27.86	$ 32.23	$ 42.73	$ 37.10
Less:						
Royalties	2.59	9.59	6.30	4.55	12.41	8.20
Operating expenses	11.39	7.47	9.31	13.13	7.58	10.55
Transportation expenses	2.24	–	1.05	3.37	–	1.81
Operating netback	$ 5.59	$ 16.16	$ 11.20	$ 11.18	$ 22.74	$ 16.54
Realized financial derivatives gain	–	–	4.49	–	–	7.13
Operating netback after financial derivatives	$ 5.59	$ 16.16	$ 15.69	$ 11.18	$ 22.74	$ 23.67

Exploration and Evaluation Expense

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

Exploration and evaluation expense was $1.2 million for Q3/2016 compared to $2.0 million in Q3/2015. Exploration and evaluation expense was $4.6 million for YTD 2016 compared to $6.5 million for YTD 2015. The decrease in expenses in 2016 compared to 2015 is due to lower expiries of undeveloped land.

Depletion and Depreciation

	Three Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[(1)]	$ 53,411	$ 64,128	$ 118,231	$ 65,525	$ 95,827	$ 162,503
Depletion and depreciation per boe	$ 17.27	$ 20.77	$ 19.13	$ 16.48	$ 26.75	$ 21.50

	Nine Months Ended September 30					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[(1)]	$ 155,039	$ 224,737	$ 381,842	$ 208,354	$ 287,030	$ 498,106
Depletion and depreciation per boe	$ 16.97	$ 21.80	$ 19.63	$ 16.59	$ 26.39	$ 21.26

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $118.2 million and $381.8 million for Q3/2016 and YTD 2016, respectively, decreased by $44.3 million and $116.3 million from the same periods in 2015. Depletion has decreased due to a lower asset base from impairment charges recorded in 2015 combined with lower production. On a per boe basis, depletion and depreciation expense for Q3/2016 and YTD 2016 of $19.13/boe and $19.63/boe, respectively, decreased from $21.50/boe and $21.26/boe for the same periods in 2015. The overall depletion rate has decreased in 2016 as we recorded $755.6 million of impairments on U.S. oil and gas properties in 2015 which reduced the depletable base and the depletion rate.

Asset Dispositions and Impairment

During Q3/2016, we sold our operated assets in the Eagle Ford along with some non-core Canadian assets for proceeds of $63 million. We recognized a gain on dispositions totaling $43.5 million for Q3/2016 and $43.4 million for YTD 2016.

Subsequent to September 30, 2016, we disposed of certain assets in the Lloydminster area. As a result, we assessed the assets for impairment at September 30, 2016 resulting in a $26.6 million impairment expense when these assets were reclassified to assets held for sale at their fair value. In Q3/2015, we recorded $493.2 million of impairment expense related to our Eagle Ford assets. This was directly attributable to lower commodity prices as the Eagle Ford assets were originally recorded at their fair value in June 2014 when WTI oil price was more than US$100/bbl.

General and Administrative Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	2016	2015	Change	2016	2015	Change
General and administrative expenses	$ 12,102	$ 13,976	(13%)	$ 38,504	$ 46,588	(17%)
General and administrative expenses per boe	$ 1.96	$ 1.85	6%	$ 1.98	$ 1.99	(1%)

General and administrative expenses for the three and nine months ended September 30, 2016 of $12.1 million and $38.5 million, respectively, decreased from $14.0 million and $46.6 million for the same periods in 2015. The decreases are attributable to reductions in staffing levels commensurate with lower activity levels combined with cost saving efforts.

Share-Based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in net 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 was $5.2 million and $13.5 million for Q3/2016 and YTD 2016, respectively, compared to $4.6 million and $22.4 million for the same periods in 2015. For YTD 2016, compensation expense decreased $8.9 million due to lower fair value of share awards granted resulting from a reduction in the Company's share price at grant date for new grants late in 2015 and 2016. Compensation expense for Q3/2016 increased $0.6 million from Q3/2015 due to the recording of forfeitures related to staff reductions in Q3/2015 which reduced the expense during the period. This was partially offset by lower fair value of share awards granted in late 2015 and in 2016 compared to grants vesting from previous years.

During the third quarter, the Company identified an immaterial error relating to share-based compensation expense in our previously issued financial statements. The estimated forfeiture rate was improperly applied to share awards that had previously vested and transferred to share capital, thereby understating share-based compensation expense. The Company concluded that the error is not material to the Company's previously filed financial statements and the corrected adjustments have been applied to the comparative financial information in these interim consolidated financial statements.

For the three months and nine months ended September 30, 2015, an additional $1.4 million and $3.0 million, respectively, of share-based compensation expense has been recorded and reflected in the comparative figures above which increased the net loss per share (basic and diluted) by $0.01 to $2.50 per share for the three months ended September 30, 2015 and by $0.02 to $3.73 per share for the nine months ended September 30, 2015.

For the year ended December 31, 2015 an additional $9.2 million of share-based compensation has been recorded resulting in a revised expense of $24.6 million. Net loss per share (basic and diluted) increased by $0.05 to $5.77 per share for the year ended December 31, 2015. For the year ended December 31, 2014 an additional $4.2 million of share-based compensation has been recorded resulting in a revised expense of $31.7 million. Net loss per share (basic and diluted) increased by $0.03 to $0.92 per share for the year ended December 31, 2014. As at December 31, 2014, both deficit and contributed surplus were increased by $8.2 million. A summary of the adjustment is disclosed in note 10 to the consolidated financial statements.

Financing and Interest Expenses

Financing and interest expenses include interest on bank loan and long-term notes, non-cash financing costs and accretion on asset retirement obligations.

Financing and interest expenses increased $0.9 million to $28.4 million for Q3/2016, compared to $27.5 million in Q3/2015 due to higher outstanding bank debt during Q3/2016.

Financing and interest expenses increased slightly to $85.4 million for YTD 2016, compared to $83.7 million in YTD 2015. This increase relates to interest on long-term notes as the Canadian dollar was weaker against the U.S. dollar in YTD 2016 compared to YTD 2015 which increased our interest expense on our long-term notes denominated in U.S. dollars.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in the value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan are translated to Canadian dollars on the balance sheet date. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. 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 September 30			Nine Months Ended September 30		
($ thousands except for % and exchange rates)	**2016**	2015	Change	**2016**	2015	Change
Unrealized foreign exchange loss (gain)	**$ 11,361**	$ 89,215	(87%)	**$ (71,891)**	$172,182	(142%)
Realized foreign exchange (gain)	**(1,248)**	(1,696)	(26%)	**(2,012)**	(1,583)	27%
Foreign exchange loss (gain)	**$ 10,113**	$ 87,519	(88%)	**$ (73,903)**	$170,599	(143%)
CAD/USD exchange rates:						
At beginning of period	**1.3009**	1.2474		**1.3840**	1.1601	
At end of period	**1.3117**	1.3394		**1.3117**	1.3394	

The Company recorded an unrealized foreign exchange loss of $11.4 million for Q3/2016 as the Canadian dollar weakened against the U.S. dollar at September 30, 2016 as compared to June 30, 2016. The Company recorded unrealized foreign exchange gain of $71.9 million for YTD 2016 as the Canadian dollar strengthened against the U.S. dollar at September 30, 2016 as compared to December 31, 2015.

The Company realizes foreign exchange gains and losses from day-to-day U.S. dollar denominated transactions in its Canadian entities. For the three and nine months ended September 30, 2016, the Company recorded realized foreign exchange gains of $1.2 million and $2.0 million, respectively compared to gains of $1.7 million and $1.6 million for the comparative periods in 2015.

Other Income/Expense

For Q3/2016 and YTD 2016, we have other expense of $10.3 million and $10.2 million, respectively, compared to other income of $2.7 million and $7.6 million in the comparative periods in 2015. In Q3/2016, we entered into agreements to sublease a portion of our 2017 firm transportation commitment and a portion of our office space. We recorded an expense of $6.7 million on the transportation agreement and $3.5 million on our office space. These expenses represent the difference between the minimum future payments that we are required to make and the estimated recoveries. For Q3/2015 and YTD 2015, we were able to sublease a portion of our 2016 firm transportation commitment at a higher rate than our contract rate which generated other income of $2.7 million and $7.6 million, respectively. These gains were recognized as they were received in 2015.

Income Taxes

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2016**	2015	Change	**2016**	2015	Change
Current income tax (recovery) expense	**$ (4,261)**	$ 178	$ (4,439)	**$ (7,987)**	$ 16,560	$ (24,547)
Deferred income tax (recovery)	**(14,589)**	(91,858)	77,269	**(109,494)**	(145,853)	36,359
Total income tax (recovery)	**$ (18,850)**	$ (91,680)	$ 72,830	**$ (117,481)**	$ (129,293)	$ 11,812

In 2016, available tax deductions exceeded taxable income which allowed the Company to recover a portion of the prior year current income tax expense. For Q3/2016, this resulted in a current income tax recovery of $4.3 million, an increase of $4.4 million over the current income tax expense of $0.2 million in Q3/2015. For YTD 2016, this resulted in a current income tax recovery of $8.0 million, an increase of $24.5 million over the current income tax expense of $16.6 million for YTD 2015.

The Q3/2016 deferred income tax recovery of $14.6 million decreased $77.3 million from $91.9 million in Q3/2015. The YTD 2016 income tax recovery of $109.5 million decreased $36.4 million from $145.9 million in YTD 2015. The decreases during 2016 for both the quarter and YTD compared to 2015 are due to the impairment expense recorded in Q3/2015 of $210.3 million related to lower commodity prices, compounded by a higher income tax rate in the U.S. The YTD 2016 decrease is partially offset by a decrease in the amount of tax pool claims required to shelter the lower taxable income.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

We have filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of the CRA; a process that we estimate could take up to two years. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available for "carry back" to the years 2012 through 2015.

Net Income (Loss) and Funds from Operations

Net loss for Q3/2016 totaled $39.4 million ($0.19 per basic and diluted share) compared to net loss of $519.2 million ($2.50 per basic and diluted share) for Q3/2015. Net loss for YTD 2016 totaled $125.8 million ($0.60 per basic and diluted share) compared to net loss of $723.7 million ($3.73 per basic and diluted share) for YTD 2015. Funds from operations for Q3/2016 totaled $72.1 million ($0.34 per basic and diluted share) as compared to $105.1 million ($0.51 per basic and diluted share) for Q3/2015. Funds from operations for YTD 2016 totaled $199.0 million ($0.94

per basic and diluted share) as compared to $423.3 million ($2.18 per basic and diluted share) for YTD 2015. The components of the change in net income (loss) and funds from operations from Q3/2015 to Q3/2016 and YTD 2015 to YTD 2016 are detailed in the following table:

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**Net income (loss)**	**Funds from operations**	**Net income (loss)**	**Funds from operations**
2015	$ **(519,247)**	$ 105,052	$ **(723,705)**	$ 423,322
Increase (decrease) in revenues				
Revenue, net of royalties	**(56,256)**	(56,256)	**(275,486)**	(275,486)
(Increase) decrease in expenses				
Operating	**21,417**	21,417	**66,297**	66,297
Transportation	**2,923**	2,923	**21,877**	21,877
Blending	**2,837**	2,837	**17,408**	17,408
General and administrative	**1,874**	1,874	**8,084**	8,084
Exploration and evaluation	**798**	–	**1,985**	–
Depletion and depreciation	**44,272**	–	**116,264**	–
Impairment	**466,668**	–	**466,668**	–
Share-based compensation	**(568)**	–	**8,879**	–
Financing and interest	**(867)**	(440)	**(1,626)**	96
Financial derivatives	**(37,997)**	(6,402)	**(92,237)**	(79,866)
Foreign exchange	**77,406**	(448)	**244,502**	429
Other(1)(2)	**30,140**	(2,890)	**27,142**	(7,696)
Current income tax	**4,439**	4,439	**24,547**	24,547
Deferred income tax	**(77,269)**	–	**(36,359)**	–
2016	$ **(39,430)**	$ **72,106**	$ **(125,760)**	$ **199,012**

(1) For net income (loss), "other" includes gain (loss) on disposition and other income/expense.

(2) For funds from operations, "other" includes the cash component of other income/expense.

Dividends

In response to the prolonged low price commodity environment and in an effort to preserve liquidity, Baytex suspended the monthly dividend beginning September 2015. During 2015, we declared monthly dividends of $0.10 per common share from January to August totaling $0.80 per common share. In total $96.6 million of the dividends were paid in cash and $57.3 million were settled by issuing 4,707,914 common shares under the Company's dividend reinvestment plan during 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 $20.3 million foreign currency translation gain for Q3/2016 is due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2016 (1.3117 CAD/USD) as compared to June 30, 2016 (1.3009 CAD/USD). The $132.4 million foreign currency translation loss for YTD 2016 is due to the strengthening of the Canadian dollar against the U.S. dollar at September 30, 2016 (1.3117 CAD/USD) as compared to December 31, 2015 (1.3840 CAD/USD).

Capital Expenditures

Capital expenditures for the three and nine months ended September 30, 2016 and 2015 are summarized as follows:

	Three Months Ended September 30					
	2016			2015		
($ thousands except for # of wells drilled)	Canada	U.S.	Total	Canada	U.S.	Total
Land	$ 997	$ –	$ 997	$ 136	$ 6,189	$ 6,325
Seismic	99	–	99	913	–	913
Drilling, completion and equipping	2,161	29,869	32,030	26,565	71,042	97,607
Facilities	2,863	3,590	6,453	5,870	16,089	21,959
Total exploration and development	$ 6,120	$ 33,459	$ 39,579	$ 33,484	$ 93,320	$ 126,804
Total acquisitions, net of proceeds from divestitures	(8,619)	(54,133)	(62,752)	(586)	89	(497)
Total oil and natural gas expenditures	$ (2,499)	$ (20,674)	$ (23,173)	$ 32,898	$ 93,409	$ 126,307
Wells drilled (net)	–	5.7	5.7	20.3	9.2	29.5

	Nine Months Ended September 30					
	2016			2015		
($ thousands except for # of wells drilled)	Canada	U.S.	Total	Canada	U.S.	Total
Land	$ 3,234	$ 6,097	$ 9,331	$ 3,664	$ 6,186	$ 9,850
Seismic	212	–	212	317	–	317
Drilling, completion and equipping	5,971	125,835	131,806	41,775	285,333	327,108
Facilities	4,308	11,097	15,405	16,690	26,278	42,968
Total exploration and development	$13,725	$143,029	$156,754	$62,446	$ 317,797	$ 380,243
Total acquisitions, net of proceeds from divestitures	(8,665)	(54,133)	(62,798)	2,234	(12)	2,222
Total oil and natural gas expenditures	$ 5,060	$ 88,896	$ 93,956	$64,680	$ 317,785	$ 382,465
Wells drilled (net)	1.0	29.5	30.5	31.4	38.4	69.8

In Q3/2016, our capital expenditures totaled $39.6 million compared to $126.8 million in Q3/2015. The significant reduction period over period is due to reduced activity levels in Canada and the Eagle Ford and from cost savings on the Eagle Ford program that were recognized in Q3/2016 as actual costs incurred were less than previously estimated. Our activities were focused on our Eagle Ford assets with 85% of the total capital being deployed in the U.S. We did not drill any wells in Canada during Q3/2016 and spent $6.1 million as compared to 20.3 net wells and $33.5 million in Q3/2015.

YTD 2016 capital expenditures totaled $156.8 million as compared to $380.2 million in YTD 2015. Capital spending has been focused on our Eagle Ford assets with YTD 2016 capital spending of $143.0 million down from $317.8 million for YTD 2015. The decrease in spending is due to lower activity levels associated with lower commodity prices combined with significant cost savings achieved on our Eagle Ford program. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$5.2 million as compared to US$8.2 million in 2014. We also recognized additional savings on drilling, completion and equipping expenditures in Q3/2016 as actual costs incurred were less than previously estimated. In Canada, we have drilled one well in YTD 2016 and have spent $13.7 million compared to YTD 2015 where we drilled 31.4 net wells and spent $62.4 million.

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 40% from our initial plans and working with our lending syndicate to secure our bank credit facilities. We also shut-in low or negative margin production for part of 2016.

If commodity prices decline from current levels, 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 September 30, 2016, net debt was $1,864.0 million, as compared to $2,049.9 million at December 31, 2015, representing a decrease of $185.9 million. This decrease is mainly due to the strengthening of the Canadian dollar against the U.S. dollar which reduced the carrying value of our U.S. dollar denominated long-term notes and bank loans at September 30, 2016 and $63 million of proceeds from asset sales that were applied to outstanding bank indebtedness. Funds from operations exceeded capital spending by $42.3 million for YTD 2016 further reducing net debt.

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 and 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 rates on the credit facilities for the three and nine months ended September 30, 2016 were 3.5%, as compared to 4.2% for the three months ended September 30, 2015 and 3.2% for the nine months ended September 30, 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 September 30, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at September 30, 2016**	**September 30, 2016 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.79:1.00**	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**3.62:1.00**	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 the bank loan and other secured obligations identified in the credit agreement. As at September 30, 2016, our Senior Secured Debt totaled $302 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 expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended September 30, 2016 was $380 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2016 were $105 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 taking on further debt or paying dividends to our shareholders.

Long-Term Notes

Baytex has five series of long-term notes outstanding that total $1.55 billion as at September 30, 2016. The long-term 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 Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at September 30, 2016, the fixed charge coverage ratio was 3.62:1.

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. As of February 17, 2016, these notes are redeemable at our option, in whole or in part, 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 our 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. As of April 1, 2016, the remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, 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 September 30, 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 November 1, 2016, we had 211,541,490 common shares and no preferred shares issued and outstanding. During the three and nine months ended September 30, 2016, we issued 826,718 and 958,516 common shares, respectively, 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 September 30, 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	**$ 120,191**	$ 120,191	$ –	$ –	$ –
Bank loan[(1)(2)]	**289,859**	–	289,859	–	–
Long-term notes[(2)]	**1,554,510**	–	–	729,830	824,680
Interest on long-term notes	**410,261**	63,299	126,598	125,654	94,710
Operating leases	**41,015**	8,248	15,584	12,979	4,204
Processing agreements	**52,252**	10,540	12,503	9,043	20,166
Transportation agreements	**60,200**	10,982	22,492	22,151	4,575
Total	**$ 2,528,288**	$ 213,260	$ 467,036	$ 899,657	$ 948,335

(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 when they reach 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

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2016, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the nine months ended September 30, 2016. Further information on our critical accounting policies and estimates can be found in the notes to the annual consolidated financial statements and MD&A for the year ended December 31, 2015.

CHANGES IN ACCOUNTING STANDARDS

We did not adopt any new accounting standards for the nine months ended September 30, 2016. A description of accounting standards that will be effective in the future is included in the notes to the audited consolidated financial statements and MD&A for the year ended December 31, 2015.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our 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 and nine months ended September 30, 2016.

QUARTERLY FINANCIAL INFORMATION

	2016			2015				2014
($ thousands, except per common share amounts)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	**197,648**	195,733	153,598	229,361	265,876	342,802	283,384	465,917
Net income (loss)	**(39,430)**	(86,937)	607	(419,175)	(519,247)	(27,096)	(177,362)	(363,019)
Per common share – basic	**(0.19)**	(0.41)	0.00	(1.99)	(2.50)	(0.13)	(1.05)	(2.17)
Per common share – diluted	**(0.19)**	(0.41)	0.00	(1.99)	(2.50)	(0.13)	(1.05)	(2.17)

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", "plan", "project", "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; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that *we would owe cash taxes and late payment interest if the reassessment is successful; 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; our belief that the amended credit facilities provide increased financial flexibility; 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 oil and 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)*	September 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash	$ 896	$ 247
Trade and other receivables	99,642	98,093
Financial derivatives	17,975	106,573
Assets held for sale (note 16)	7,400	–
	125,913	204,913
Non-current assets		
Financial derivatives	1,036	4,417
Exploration and evaluation assets (note 4)	543,756	578,969
Oil and gas properties (note 5)	4,301,184	4,674,175
Other plant and equipment	23,987	26,024
	$ 4,995,876	$ 5,488,498
LIABILITIES		
Current liabilities		
Trade and other payables	$ 120,191	$ 267,838
Financial derivatives	10,929	–
Onerous contracts	10,118	–
Liabilities related to assets held for sale (note 16)	4,360	–
	145,598	267,838
Non-current liabilities		
Bank loan (note 6)	286,034	252,172
Long-term notes (note 7)	1,536,191	1,602,757
Asset retirement obligations (note 8)	331,301	296,002
Deferred income tax liability	524,754	655,255
Financial derivatives	2,140	–
	2,826,018	3,074,024
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 9)	4,313,072	4,296,831
Contributed surplus (note 10)	19,345	22,045
Accumulated other comprehensive income	572,985	705,382
Deficit (note 10)	(2,735,544)	(2,609,784)
	2,169,858	2,414,474
	$ 4,995,876	$ 5,488,498

Subsequent event (note 16)

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 September 30 2016	2015	Nine Months Ended September 30 2016	2015
Revenue, net of royalties				
Petroleum and natural gas sales	**$ 197,648**	$ 265,876	**$ 546,979**	$ 892,062
Royalties	**(45,531)**	(57,503)	**(122,499)**	(192,096)
	152,117	208,373	**424,480**	699,966
Expenses				
Operating	**56,073**	77,490	**181,028**	247,325
Transportation	**8,533**	11,456	**20,454**	42,331
Blending	**1,587**	4,424	**5,153**	22,561
General and administrative	**12,102**	13,976	**38,504**	46,588
Exploration and evaluation (note 4)	**1,205**	2,003	**4,564**	6,549
Depletion and depreciation	**118,231**	162,503	**381,842**	498,106
Impairment (note 16)	**26,559**	493,227	**26,559**	493,227
Share-based compensation (note 10)	**5,168**	4,600	**13,541**	22,420
Financing and interest (note 13)	**28,409**	27,542	**85,350**	83,724
Financial derivatives (gain) loss (note 15)	**(24,389)**	(62,386)	**17,856**	(74,381)
Foreign exchange loss (gain) (note 14)	**10,113**	87,519	**(73,903)**	170,599
Disposition of oil and gas properties (gain) loss (note 5)	**(43,453)**	(305)	**(43,431)**	1,525
Other expense (income)	**10,259**	(2,749)	**10,204**	(7,610)
	210,397	819,300	**667,721**	1,552,964
Net income (loss) before income taxes	**(58,280)**	(610,927)	**(243,241)**	(852,998)
Income tax (recovery) expense (note 12)				
Current income tax (recovery) expense	**(4,261)**	178	**(7,987)**	16,560
Deferred income tax (recovery)	**(14,589)**	(91,858)	**(109,494)**	(145,853)
	(18,850)	(91,680)	**(117,481)**	(129,293)
Net income (loss) attributable to shareholders	**$ (39,430)**	$ (519,247)	**$ (125,760)**	$ (723,705)
Other comprehensive income (loss)				
Foreign currency translation adjustment	**20,250**	217,122	**(132,397)**	416,375
Comprehensive income (loss)	**$ (19,180)**	$ (302,125)	**$ (258,157)**	$ (307,330)
Net income (loss) per common share (note 11)				
Basic	**$ (0.19)**	$ (2.50)	**$ (0.60)**	$ (3.73)
Diluted	**$ (0.19)**	$ (2.50)	**$ (0.60)**	$ (3.73)
Weighted average common shares (note 11)				
Basic	**211,479**	207,988	**210,953**	194,143
Diluted	**211,479**	207,988	**210,953**	194,143

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 (loss)	Deficit	**Total equity**
Balance at December 31, 2014 (note 10)	$ 3,580,825	$ 39,308	$ 199,575	$ (1,312,931)	**2,506,777**
Dividends to shareholders	–	–	–	(153,973)	**(153,973)**
Vesting of share awards	28,856	(28,856)	–	–	**–**
Share-based compensation (note 10)	–	22,420	–	–	**22,420**
Issued for cash	632,494	–	–	–	**632,494**
Issuance costs, net of tax	(19,301)	–	–	–	**(19,301)**
Issued pursuant to dividend reinvestment plan	60,977	–	–	–	**60,977**
Comprehensive income (loss) for the period	–	–	416,375	(723,705)	**(307,330)**
Balance at September 30, 2015 (note 10)	$ 4,283,851	$ 32,872	$ 615,950	$ (2,190,609)	**2,742,064**
Balance at December 31, 2015 (note 10)	4,296,831	22,045	705,382	(2,609,784)	**2,414,474**
Vesting of share awards	16,241	(16,241)	–	–	**–**
Share-based compensation	–	13,541	–	–	**13,541**
Comprehensive income (loss) for the period	–	–	(132,397)	(125,760)	**(258,157)**
Balance at September 30, 2016	$ 4,313,072	$ 19,345	$ 572,985	$ (2,735,544)	**2,169,858**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars) (unaudited)	Three Months Ended September 30 2016	Three Months Ended September 30 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	$ (39,430)	$ (519,247)	$ (125,760)	$ (723,705)
Adjustments for:				
Share-based compensation (note 10)	5,168	4,600	13,541	22,420
Unrealized foreign exchange loss (gain) (note 14)	11,361	89,215	(71,891)	172,182
Exploration and evaluation (note 4)	1,205	2,003	4,564	6,549
Depletion and depreciation	118,231	162,503	381,842	498,106
Impairment (note 16)	26,559	493,227	26,559	493,227
Non-cash financing and interest (note 13)	2,575	2,148	7,916	6,194
Non-cash other expense	10,118	–	10,118	–
Unrealized financial derivatives (gain) loss (note 15)	(5,639)	(37,234)	105,048	92,677
Disposition of oil and gas properties (gain) loss (note 5)	(43,453)	(305)	(43,431)	1,525
Deferred income tax (recovery)	(14,589)	(91,858)	(109,494)	(145,853)
Change in non-cash working capital	17,180	46,132	11,997	61,216
Asset retirement obligations settled (note 8)	(399)	(2,273)	(2,808)	(9,879)
	88,887	148,911	208,201	474,659
Financing activities				
Payment of dividends	–	(26,655)	–	(109,806)
Increase (decrease) in bank loan	(60,883)	2,989	43,724	(479,593)
Tenders of long-term notes	–	–	–	(10,372)
Issuance of common shares, net of issuance costs	–	–	–	606,095
	(60,883)	(23,666)	43,724	6,324
Investing activities				
Additions to exploration and evaluation assets (note 4)	(971)	(834)	(3,544)	(4,532)
Additions to oil and gas properties (note 5)	(38,608)	(125,970)	(153,210)	(375,711)
Property acquisitions	(108)	498	(62)	(2,222)
Proceeds from disposition of oil and gas properties	62,860	–	62,860	–
Current income tax paid on dispositions	–	–	–	(8,181)
Additions to other plant and equipment, net of disposals	164	425	(210)	5,131
Change in non-cash working capital	(51,075)	399	(155,393)	(97,408)
	(27,738)	(125,482)	(249,559)	(482,923)
Impact of foreign currency translation on cash balances	211	196	(1,717)	1,031
Change in cash	477	(41)	649	(909)
Cash, beginning of period	419	274	247	1,142
Cash, end of period	$ 896	$ 233	$ 896	$ 233
Supplementary information				
Interest paid	$ 20,868	$ 18,732	$ 72,744	$ 69,082
Income taxes paid	$ 116	$ (293)	$ 5,254	$ 7,888

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS

For the three and nine months ended September 30, 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.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2015 are available through our filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

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 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 November 1, 2016.

The consolidated financial statements have been prepared on a 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, including the adjustments relating to share-based compensation (see note 10).

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 USA.
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 83,602**	$ 119,984	**$ 114,046**	$ 145,892	**$ –**	$ –	**$ 197,648**	$ 265,876
Royalties	**(11,918)**	(15,445)	**(33,613)**	(42,058)	**–**	–	**(45,531)**	(57,503)
	71,684	104,539	**80,433**	103,834	**–**	–	**152,117**	208,373
Expenses								
Operating	**38,115**	48,946	**17,958**	28,544	**–**	–	**56,073**	77,490
Transportation	**8,533**	11,456	**–**	–	**–**	–	**8,533**	11,456
Blending	**1,587**	4,424	**–**	–	**–**	–	**1,587**	4,424
General and administrative	**–**	–	**–**	–	**12,102**	13,976	**12,102**	13,976
Exploration and evaluation	**1,205**	2,003	**–**	–	**–**	–	**1,205**	2,003
Depletion and depreciation	**53,411**	65,525	**64,128**	95,827	**692**	1,151	**118,231**	162,503
Impairment	**26,559**	–	**–**	493,227	**–**	–	**26,559**	493,227
Share-based compensation (note 10)	**–**	–	**–**	–	**5,168**	4,600	**5,168**	4,600
Financing and interest	**–**	–	**–**	–	**28,409**	27,542	**28,409**	27,542
Financial derivatives (gain)	**–**	–	**–**	–	**(24,389)**	(62,386)	**(24,389)**	(62,386)
Foreign exchange loss	**–**	–	**–**	–	**10,113**	87,519	**10,113**	87,519
Disposition of oil and gas properties (gain) loss	**(3,510)**	(305)	**(39,921)**	–	**(22)**	–	**(43,453)**	(305)
Other expense (income)	**–**	–	**–**	–	**10,259**	(2,749)	**10,259**	(2,749)
	125,900	132,049	**42,165**	617,598	**42,332**	69,653	**210,397**	819,300
Net income (loss) before income taxes	**(54,216)**	(27,510)	**38,268**	(513,764)	**(42,332)**	(69,653)	**(58,280)**	(610,927)
Income tax (recovery) expense								
Current income tax (recovery) expense	**(4,261)**	(1,852)	**–**	2,030	**–**	–	**(4,261)**	178
Deferred income tax (recovery) expense	**(10,142)**	64,820	**1,718**	(147,892)	**(6,165)**	(8,786)	**(14,589)**	(91,858)
	(14,403)	62,968	**1,718**	(145,862)	**(6,165)**	(8,786)	**(18,850)**	(91,680)
Net income (loss)	**$ (39,813)**	$ (90,478)	**$ 36,550**	$(367,902)	**$ (36,167)**	$ (60,867)	**$ (39,430)**	$(519,247)
Total oil and natural gas capital expenditures[1]	**$ (2,499)**	$ 32,898	**$ (20,674)**	$ 93,409	**$ –**	$ –	**$ (23,173)**	$ 126,307

(1) *Includes acquisitions, net of proceeds from divestitures.*

Nine Months Ended September 30	Canada 2016	Canada 2015	U.S. 2016	U.S. 2015	Corporate 2016	Corporate 2015	Consolidated 2016	Consolidated 2015
Revenue, net of royalties								
Petroleum and natural gas sales	$ 204,446	$ 427,248	$ 342,533	$ 464,814	$ –	$ –	$ 546,979	$ 892,062
Royalties	(23,673)	(57,122)	(98,826)	(134,974)	–	–	(122,499)	(192,096)
	180,773	370,126	243,707	329,840	–	–	424,480	699,966
Expenses								
Operating	104,040	164,860	76,988	82,465	–	–	181,028	247,325
Transportation	20,454	42,331	–	–	–	–	20,454	42,331
Blending	5,153	22,561	–	–	–	–	5,153	22,561
General and administrative	–	–	–	–	38,504	46,588	38,504	46,588
Exploration and evaluation	4,564	6,549	–	–	–	–	4,564	6,549
Depletion and depreciation	155,039	208,354	224,737	287,030	2,066	2,722	381,842	498,106
Impairment	26,559	–	–	493,227	–		26,559	493,227
Share-based compensation (note 10)	–	–	–	–	13,541	22,420	13,541	22,420
Financing and interest	–	–	–	–	85,350	83,724	85,350	83,724
Financial derivatives loss (gain)	–	–	–	–	17,856	(74,381)	17,856	(74,381)
Foreign exchange (gain) loss	–	–	–	–	(73,903)	170,599	(73,903)	170,599
Disposition of oil and gas properties (gain) loss	(3,510)	1,769	(39,921)	(244)	–	–	(43,431)	1,525
Other expense (income)	–	–	–	–	10,204	(7,610)	10,204	(7,610)
	312,299	446,424	261,804	862,478	93,618	244,062	667,721	1,552,964
Net income (loss) before income taxes	(131,526)	(76,298)	(18,097)	(532,638)	(93,618)	(244,062)	(243,241)	(852,998)
Income tax (recovery) expense								
Current income tax (recovery) expense	(7,661)	12,673	–	3,887	(326)	–	(7,987)	16,560
Deferred income tax (recovery) expense	(28,690)	24,711	(43,610)	(129,631)	(37,194)	(40,933)	(109,494)	(145,853)
	(36,351)	37,384	(43,610)	(125,744)	(37,520)	(40,933)	(117,481)	(129,293)
Net income (loss)	$ (95,175)	$(113,682)	$ 25,513	$(406,894)	$ (56,098)	$(203,129)	$(125,760)	$(723,705)
Total oil and natural gas capital expenditures[(1)]	$ 5,060	$ 64,680	$ 88,896	$ 317,785	$ –	$ –	$ 93,956	$ 382,465

(1) Includes acquisitions, net of proceeds from divestitures.

As at	September 30, 2016	December 31, 2015
Canadian assets	$ 1,910,728	$ 2,059,903
U.S. assets	3,055,007	3,304,647
Corporate assets	30,141	123,948
Total consolidated assets	$ 4,995,876	$ 5,488,498

4. EXPLORATION AND EVALUATION ASSETS

	September 30, 2016	December 31, 2015
Balance, beginning of period	$ 578,969	$ 542,040
Capital expenditures	3,544	5,642
Property acquisitions, net of divestitures	62	1,813
Exploration and evaluation expense	(4,564)	(8,775)
Transfer to oil and gas properties	(7,595)	(38,062)
Divestitures	(2,618)	(1,588)
Foreign currency translation	(24,042)	77,899
Balance, end of period	$ 543,756	$ 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	**$ 7,584,281**	**$ (2,910,106)**	**$ 4,674,175**
Capital expenditures	153,210	–	153,210
Transferred from exploration and evaluation assets	7,595	–	7,595
Change in asset retirement obligations	39,673	–	39,673
Divestitures	(18,843)	5,497	(13,346)
Impairment (note 16)	–	(26,559)	(26,559)
Transferred to assets held for sale (note 16)	(44,863)	37,463	(7,400)
Foreign currency translation	(182,059)	35,497	(146,562)
Depletion	–	(379,602)	(379,602)
Balance, September 30, 2016	**$ 7,538,994**	**$ (3,237,810)**	**$ 4,301,184**

On July 27, 2016, the Company disposed of its operated interest in certain Eagle Ford properties for proceeds of $54.6 million, which consisted of $11.8 million of oil and gas properties and $2.4 million of exploration and evaluations assets for a gain on disposition of $39.9 million.

In 2016, the Company disposed of certain non-core assets in Canada for total proceeds of $8.3 million, which consisted of $1.5 million of oil and gas properties and $0.3 million of evaluation and exploration assets, for a gain on disposition of $6.5 million.

6. BANK LOAN

	September 30, 2016	December 31, 2015
Bank loan – U.S. dollar denominated	$ 276,486	$ 237,861
Bank loan – Canadian dollar denominated	13,373	18,888
Bank loan – principal	289,859	256,749
Unamortized debt issuance costs	(3,825)	(4,577)
Bank loan	$ 286,034	$ 252,172

On March 31, 2016, Baytex amended its credit facilities 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 and a US$350 million syndicated loan for Baytex and a US$200 million syndicated loan for Baytex's 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 of 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, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At September 30, 2016, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants contained in the Revolving Facilities and Baytex's compliance therewith as at September 30, 2016.

	Ratio for the Quarter(s) ending:				
Covenant Description	Position as at September 30, 2016	September 30, 2016 to June 30, 2018	June 30, 2018 to September 30, 2018	December 31, 2018	Thereafter
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	0.79:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	3.62:1.00	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 the bank loan and other secured obligations identified in the credit agreement. As at September 30, 2016, our Senior Secured Debt totaled $302 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 expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended September 30, 2016 was $380 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2016 were $105 million.

7. LONG-TERM NOTES

	September 30, 2016	December 31, 2015
7.5% notes (US$6,400 – principal) due April 1, 2020	$ 8,395	$ 8,858
6.75% notes (US$150,000 – principal) due February 17, 2021	196,755	207,600
5.125% notes (US$400,000 – principal) due June 1, 2021	524,680	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	524,680	553,600
Total long-term notes – principal	1,554,510	1,623,658
Unamortized debt issuance costs	(18,319)	(20,901)
Total long-term notes – net of unamortized debt issuance costs	$ 1,536,191	$ 1,602,757

8. ASSET RETIREMENT OBLIGATIONS

	September 30, 2016	December 31, 2015
Balance, beginning of period	$ 296,002	$ 286,032
Liabilities incurred	4,130	4,964
Liabilities settled	(2,808)	(10,888)
Liabilities acquired	–	593
Liabilities divested	(5,114)	(10,578)
Accretion	4,702	6,262
Change in estimate[(1)]	(279)	33,266
Changes in discount rates and inflation rates[(2)]	40,936	(17,523)
Liabilities related to assets held for sale (note 16)	(4,360)	–
Foreign currency translation	(1,908)	3,874
Balance, end of period	$ 331,301	$ 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.

(2) The discount rate and inflation rate at September 30, 2016 are 1.75% and 1.5%, respectively, compared to 2.25% and 1.5% at December 31, 2015.

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 September 30, 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	959	16,241
Balance, September 30, 2016	211,542	$ 4,313,072

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 3.8% 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 $5.2 million for the three months ended September 30, 2016 ($4.6 million for the three months ended September 30, 2015) and $13.5 million for the nine months ended September 30, 2016 ($22.4 million for the nine months ended September 30, 2015).

The weighted average fair value of share awards granted during the nine months ended September 30, 2016 was $3.05 per restricted and performance award (for the nine months ended September 30, 2015, $17.17 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	1,313	1,578	2,891
Vested and converted to common shares	(450)	(409)	(859)
Forfeited	(74)	(41)	(115)
Balance, September 30, 2016	**1,518**	**1,741**	**3,259**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.

During the third quarter, the Company identified an immaterial error relating to share-based compensation expense in the previously issued financial statements. The estimated forfeiture rate was improperly applied to share awards that had previously vested and transferred to share capital, thereby understating share-based compensation expense. The Company concluded that the error is not material to the Company's previously filed financial statements and the corrected adjustments have been applied to the comparative financial information in these interim consolidated financial statements.

For the three and nine month periods ended September 30, 2015, an additional $1.4 million and $3.0 million, respectively, have been recorded to share-based compensation expense. Net loss per share (basic and diluted) increased by $0.01 per share to $2.50 per share for the three months ended September 30, 2015 and $0.02 per share to $3.73 per share for the nine months ended September 30, 2015. For the year ended December 31, 2015, an additional $9.2 million has been recorded to share-based compensation expense and contributed surplus. Net loss per share (basic and diluted) increased by $0.05 per share to $5.77 per share for the year ended December 31, 2015. As at December 31, 2014, both deficit and contributed surplus were increased by $8.2 million.

11. NET INCOME (LOSS) PER SHARE

	Three Months Ended September 30					
	2016			2015		
	Net loss	Common shares *(000s)*	Net loss per share	Net loss	Common shares *(000s)*	Net loss per share
Net income (loss) – basic	$ (39,430)	211,479	$ (0.19)	$ (519,247)	207,988	$ (2.50)
Dilutive effect of share awards	–	–	–	–	–	–
Net income (loss) – diluted	$ (39,430)	211,479	$ (0.19)	$ (519,247)	207,988	$ (2.50)

	Nine Months Ended September 30					
	2016			2015		
	Net loss	Common shares *(000s)*	Net loss per share	Net loss	Common shares *(000s)*	Net loss per share
Net income (loss) – basic	$ (125,760)	210,953	$ (0.60)	$ (723,705)	194,143	$ (3.73)
Dilutive effect of share awards	–	–	–	–	–	–
Net income (loss) – diluted	$ (125,760)	210,953	$ (0.60)	$ (723,705)	194,143	$ (3.73)

For the three months ended September 30, 2016, 3.3 million share awards were anti-dilutive (September 30, 2015 – 1.7 million share awards). For the nine months ended September 30, 2016, 3.3 million share awards were anti-dilutive (September 30, 2015 – 1.7 million share awards).

12. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2016	2015
Net income (loss) before income taxes	$ (243,241)	$ (852,998)
Expected income taxes at the statutory rate of 27.00% (2015 – 26.23%)[(1)]	(65,675)	(223,741)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	3,590	5,881
Non-taxable portion of foreign exchange (gain) loss	(9,271)	22,340
Effect of change in income tax rates[(1)]	–	10,621
Effect of rate adjustments for foreign jurisdictions	(38,342)	(57,119)
Effect of change in deferred tax benefit not recognized[(2)]	(9,271)	34,414
Impairment of goodwill	–	74,215
Other	1,488	4,096
Income tax (recovery)	$ (117,481)	$ (129,293)

(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 $114 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 June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter from the CRA received by Baytex in November 2014 proposing to issue such reassessments.

Baytex remains confident that the tax filings of the affected entities are correct and has filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of CRA; a process that Baytex estimates could take up to two years. If the Appeals Division upholds the notices of reassessment Baytex has the right to appeal to the Tax Court of Canada; a process that Baytex estimates could take a further two years. Should Baytex be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that Baytex estimates could take another two years and potentially longer. The reassessments do not require Baytex to pay any amounts in order to participate in the appeals process.

By way of background, Baytex acquired all of the interests in several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, Baytex would owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available for "carry back" to the years 2012 through 2015.

13. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2016	2015	2016	2015
Interest on bank loan	$ 3,260	$ 2,714	$ 9,560	$ 11,477
Interest on long-term notes	22,574	22,680	67,874	66,053
Non-cash financing	1,103	547	3,214	1,427
Accretion on asset retirement obligations	1,472	1,601	4,702	4,767
Financing and interest	$ 28,409	$ 27,542	$ 85,350	$ 83,724

14. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2016	2015	2016	2015
Unrealized foreign exchange loss (gain)	$ 11,361	$ 89,215	$ (71,891)	$ 172,182
Realized foreign exchange (gain)	(1,248)	(1,696)	(2,012)	(1,583)
Foreign exchange loss (gain)	$ 10,113	$ 87,519	$ (73,903)	$ 170,599

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	
	September 30, 2016	December 31, 2015	September 30, 2016	December 31, 2015
U.S. dollar denominated	US$65,363	US$124,218	US$1,212,720	US$1,240,308

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	October 2016 to December 2016	5,000 bbl/d	US$63.79	WTI
Producer 3-way option[2]	October 2016 to December 2016	10,000 bbl/d	US$59.85/US$49.75/US$39.75	WTI
Producer 3-way option[2]	January 2017 to December 2017	13,500 bbl/d	US$58.48/US$46.96/US$37.04	WTI
Basis swap	October 2016 to December 2016	5,000 bbl/d	WTI less US$13.29	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	3,000 bbl/d	US$55.50	WTI
Sold call option[4]	January 2017 to December 2017	1,500 bbl/d	US$54.60	WTI
Producer 3-way option[2][5]	January 2017 to December 2017	1,000 bbl/d	US$60.40/US$50.00/US$40.00	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 a $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 the market price 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. Option expired subsequent to September 30, 2016 without the counterparty exercising the option.

(4) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted. Option expires on December 30, 2016.

(5) Contract entered subsequent to September 30, 2016.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	October 2016 to December 2016	15,000 mmBtu/d	US$2.98	NYMEX
Fixed – Sell	January 2017 to December 2017	17,500 mmBtu/d	US$2.83	NYMEX
Fixed – Sell	January 2018 to December 2018	7,500 mmBtu/d	US$3.00	NYMEX
Fixed – Sell	October 2016 to December 2016	32,500 GJ/d	$2.39	AECO
Fixed – Sell	January 2017 to December 2017	12,500 GJ/d	$2.65	AECO
Fixed – Sell	January 2018 to December 2018	5,000 GJ/d	$2.67	AECO
Fixed – Sell[2]	January 2017 to December 2017	5,000 GJ/d	$3.03	AECO

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

(2) Contract entered subsequent to September 30, 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 September 30		Nine Months Ended September 30	
	2016	2015	**2016**	2015
Realized financial derivatives (gain)	**$ (18,750)**	$ (25,152)	**$ (87,192)**	$ (167,058)
Unrealized financial derivatives (gain) loss – commodity	**(5,639)**	(43,012)	**105,048**	92,179
Unrealized financial derivatives (gain) – redemption feature on long-term notes	**–**	5,778	**–**	498
Financial derivatives (gain) loss	**$ (24,389)**	$ (62,386)	**$ 17,856**	$ (74,381)

Physical Delivery Contracts

As at September 30, 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	October 2016 to December 2016	2,500 bbl/d	WTI less US$13.83
WCS Blend	November 2016 to December 2016	500 bbl/d	WTI less US$14.40

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

As at September 30, 2016, Baytex had committed to deliver the following volumes of raw bitumen as noted below to market on rail:

	Period	Term volume
Raw bitumen	October 2016 to December 2016	7,400 bbl/d
Raw bitumen	January 2017 to December 2017	5,000 bbl/d

16. SUBSEQUENT EVENT

On October 5, 2016, Baytex disposed certain Saskatchewan properties for consideration of approximately $3.0 million. At September 30, 2016, $7.4 million of oil and gas properties relating to the disposition were reclassified to assets held for sale, $4.4 million of asset retirement obligations were reclassified to liabilities related to assets held for sale and an impairment of $26.6 million relating to the oil and gas properties to be disposed was recorded.

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

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Chairman of the Board
Baytex Energy Corp.

James L. Bowzer
Chief Executive Officer
Baytex Energy Corp.

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

Edward Chwyl(2)(3)
Lead Independent Director
Baytex Energy Corp.
Independent Businessman

Trudy M. Curran(1)(4)
Independent Businesswoman

Naveen Dargan(1)(2)
Independent Businessman

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

Gregory K. Melchin(1)(4)
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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OFFICERS

James L. Bowzer
Chief Executive Officer

Edward D. LaFehr
President

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
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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

KPMG 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