BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and six months ended June 30, 2016
Dated July 27, 2016

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2016. This information is provided as of July 27, 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 six months ended June 30, 2016 ("YTD 2016") have been compared with the results for the six months ended June 30, 2015 ("YTD 2015") and the results for the three months ended June 30, 2016 ("Q2/2016") have been compared with the results for the three months ended June 30, 2015 ("Q2/2015"). 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 six months ended June 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 June 30		Six Months Ended June 30	
($ thousands)	**2016**	2015	**2016**	2015
Cash flow from operating activities	**$ 54,961**	$ 137,848	**$ 119,314**	$ 325,748
Change in non-cash working capital	**25,592**	17,042	**5,183**	(15,084)
Asset retirement expenditures	**708**	3,160	**2,409**	7,606
Funds from operations	**$ 81,261**	$ 158,050	**$ 126,906**	$ 318,270

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 June 30, 2016 and December 31, 2015.

($ thousands)	**June 30, 2016**	December 31, 2015
Bank loan[(1)]	**$ 347,083**	$ 256,749
Long-term notes[(1)]	**1,544,181**	1,623,658
Working capital deficiency[(2)(3)]	**51,274**	169,498
Net debt	**$ 1,942,538**	$ 2,049,905

(1) Principal amount of instruments.
(2) Working capital is current assets less current liabilities (excluding current financial derivatives and assets held for sale).
(3) In the oil and gas industry, it is not unusual to have a working capital deficiency as accounts receivable arising from sales of production are usually settled within one or two months but accounts payable related to capital and operating expenditures are usually settled over a longer time span (often two to four months) due to vendor billing cycles and internal approval processes.

Operating Netback

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

Bank EBITDA

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

The following table reconciles net income (loss) (a GAAP measure) to Bank EBITDA (a non-GAAP measure).

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2016**	2015	**2016**	2015
Net income (loss)	**$ (86,937)**	$ (26,955)	**$ (86,330)**	$ (202,871)
Plus:				
Financing and interest	**27,888**	26,772	**56,941**	56,182
Unrealized foreign exchange loss (gain)	**3,548**	(18,349)	**(83,252)**	82,967
Unrealized financial derivatives loss	**80,564**	41,739	**110,687**	129,911
Current income tax (recovery) expense	**(2,284)**	(553)	**(3,726)**	16,382
Deferred income tax (recovery)	**(46,783)**	(12,313)	**(94,905)**	(53,995)
Depletion and depreciation	**121,940**	161,476	**263,611**	335,603
Non-cash items[(1)]	**5,829**	10,400	**11,754**	22,609
Bank EBITDA	**$ 103,765**	$ 182,217	**$ 174,780**	$ 386,788

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

SECOND QUARTER HIGHLIGHTS

In Q2/2016, commodity prices improved from Q1/2016 and our funds from operations increased 78% with higher realized pricing and lower operating costs. We continue to prudently manage our capital program with funds from operations exceeding capital expenditures for both Q2/2016 and YTD 2016.

The price of West Texas Intermediate light oil ("WTI") ranged from a low of US$26.21/bbl in February 2016 to a high of US$51.23/bbl in June 2016. WTI averaged US$45.60/bbl in Q2/2016 up from US$33.45/bbl in Q1/2016 but was still down from US$57.94/bbl in Q2/2015. With improved commodity prices, FFO increased 78% from Q1/2016 to $81.3 million in Q2/2016. Our average sales price increased 39% to $30.52/boe in Q2/2016 compared to $21.93/boe in Q1/2016. WTI has averaged US$39.53/bbl during 2016, a decrease of 26% as compared to the first six months of 2015.

Production averaged 70,031 boe/d during Q2/2016, a decrease of 8% from Q1/2016. This decrease is a result of reduced capital spending combined with low or negative margin production that was shut-in during the first half of the quarter. Canadian production averaged 31,722 boe/d for Q2/2016, a decrease of 9% from Q1/2016. With improved pricing, 6,500 boe/d of previously shut-in production was brought back on during the second half of Q2/2016. The Company still has approximately 1,000 boe/d of production in Canada shut-in. U.S. production averaged 38,309 boe/d for Q2/2016 which was down approximately 7% from 41,067 boe/d in

Q1/2016. This decrease was largely anticipated due to a reduction in the rigs and completion crews on our Eagle Ford lands during 2016 in response to the lower commodity prices. Production averaged 72,902 boe/d during YTD 2016 down 17% as compared to YTD 2015. The decrease from 2015 is mainly attributed to the limited amount of capital spending in Canada over the last 18 months combined with low or negative margin production that was shut in. The reduced capital spending in the Eagle Ford is also contributing to the decrease from the prior year.

Funds from operations for Q2/2016 was $81.3 million ($0.39 per basic and diluted share) compared to $45.6 million ($0.22 per basic and diluted share) in Q1/2016. The 78% increase in FFO is attributable to higher commodity prices and lower operating costs in the quarter which was partially offset by lower hedging gains. FFO for YTD 2016 of $126.9 million is down 60% from YTD 2015 and is directly attributable to lower commodity prices, lower production volumes in Canada and lower realized financial derivatives gain.

Capital activity in the current quarter slowed from Q1/2016 with capital expenditures totaling $35.5 million, a decrease of $46.2 million from Q1/2016 and $71.7 million from Q2/2015. Despite lower activity levels in Q2/2016, 92% of total capital spending was focused on our Eagle Ford assets. Capital spending in the Eagle Ford totaled $32.7 million in Q2/2016 where we drilled 11.3 net wells, completed 7.2 net wells and brought 5.7 net wells on-stream. There was very limited activity in Canada in Q2/2016 with total capital spending of $2.7 million as compared to $7.7 million in Q2/2015.

With reduced capital spending and higher commodity prices, our net debt decreased to $1.94 billion at June 30, 2016 from $2.05 billion at December 31, 2015. At June 30, 2016, we were in compliance with all of our financial covenants with approximately $410 million in undrawn credit capacity.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended June 30					
	2016			2015		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**22,423**	**—**	**22,423**	35,397	—	35,397
Light oil and condensate	**1,461**	**20,433**	**21,894**	1,900	23,999	25,899
NGL	**1,268**	**8,566**	**9,834**	1,085	7,147	8,232
Total liquids (bbl/d)	**25,152**	**28,999**	**54,151**	38,382	31,146	69,528
Natural gas (mcf/d)	**39,422**	**55,859**	**95,281**	41,042	50,414	91,456
Total production (boe/d)	**31,722**	**38,309**	**70,031**	45,222	39,548	84,770
Production Mix						
Heavy oil	**71%**	**—%**	**32%**	78%	—%	41%
Light oil and condensate	**5%**	**54%**	**31%**	4%	61%	31%
NGL	**4%**	**22%**	**14%**	3%	18%	10%
Natural gas	**20%**	**24%**	**23%**	15%	21%	18%

	Six Months Ended June 30					
	2016			2015		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**23,615**	**—**	**23,615**	37,302	—	37,302
Light oil and condensate	**1,513**	**21,678**	**23,191**	1,995	24,976	26,971
NGL	**1,301**	**8,670**	**9,971**	1,162	7,066	8,228
Total liquids (bbl/d)	**26,429**	**30,348**	**56,777**	40,459	32,042	72,501
Natural gas (mcf/d)	**40,712**	**56,038**	**96,750**	41,645	49,589	91,234
Total production (boe/d)	**33,214**	**39,688**	**72,902**	47,400	40,307	87,707
Production Mix						
Heavy oil	**71%**	**—%**	**32%**	79%	—%	43%
Light oil and condensate	**5%**	**55%**	**32%**	4%	62%	31%
NGL	**4%**	**22%**	**14%**	2%	18%	9%
Natural gas	**20%**	**23%**	**22%**	15%	20%	17%

Production for Q2/2016 averaged 70,031 boe/d, a 17% decrease from Q2/2015. U.S. production averaged 38,309 boe/d in Q2/2016 which was a slight decrease from Q2/2015 with less capital spending in Q2/2016 and fewer wells coming on production. Production in Canada averaged 31,722 boe/d, a 30% decrease from Q2/2015. Production has decreased with natural declines as there has been minimal capital spending in Canada over the last 18 months along with 7,500 boe/d of low or negative margin production that was shut-in. With increased commodity prices approximately 6,500 boe/d of the shut-in production was brought back on by the end of June 2016. The shut-in volumes reduced average production in Q2/2016 by approximately 4,250 boe/d.

Production for YTD 2016 averaged 72,902 boe/d, a 17% decrease from YTD 2015. U.S. production averaged 39,688 boe/d in YTD 2016 and was relatively unchanged from YTD 2015 with continued capital investment in the Eagle Ford offsetting the production declines. Canadian production of 33,214 boe/d decreased 30%, or 14,186 boe/d, from YTD 2015 due to minimal capital investment along with low or negative margin production that was shut-in. The shut-in volumes reduced average production in YTD 2016 by approximately 4,600 boe/d.

Commodity Prices

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

Crude Oil
For Q2/2016, the WTI oil prompt averaged US$45.60/bbl, a 21% decrease from the average WTI price of US$57.94/bbl in Q2/2015. For YTD 2016, the WTI oil prompt averaged US$39.53/bbl, a 26% decrease from the average WTI price of US$53.29/bbl for YTD 2015. The low prices experienced during 2016, as compared to 2015, were due to the continued global oversupply of crude oil and on-going concerns due to the high levels of inventory in storage.

The discount for Canadian heavy oil is measured by the Western Canadian Select ("WCS") price differential to WTI. For the three and six months ended June 30, 2016, the WCS heavy oil differential averaged US$13.31/bbl and US$13.77/bbl, respectively, compared to US$11.59/bbl and US$13.15/bbl for the same periods in 2015. Over the past year, increased pipeline capacity from Canada to the U.S. Gulf Coast has allowed WCS pricing to achieve pipeline equivalency with the large waterborne Gulf Coast refinery market.

Natural Gas
For the three and six months ended June 30, 2016, the AECO natural gas prices averaged $1.25/mcf and $1.68/mcf, respectively, a decrease compared to $2.67/mcf and $2.81/mcf for the same periods in 2015. For the three and six months ended June 30, 2016, the NYMEX natural gas price averaged US$1.95/mmbtu and US$2.02/mmbtu, respectively, a decrease compared to US$2.64/mmbtu and US$2.81/mmbtu for the same periods in 2015. The decrease in natural gas prices on both indices during 2016 was driven by historically high production levels and extremely weak weather related demand compared to 2015.

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

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	Change	**2016**	2015	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**45.60**	57.94	(21)%	**39.53**	53.29	(26)%
WCS heavy oil (US$/bbl)[2]	**32.29**	46.35	(30)%	**25.76**	40.14	(36)%
WCS heavy oil (CAD$/bbl)	**41.61**	56.98	(27)%	**34.31**	49.59	(31)%
LLS oil (US$/bbl)[3]	**46.20**	62.38	(26)%	**39.73**	56.47	(30)%
CAD/USD average exchange rate	**1.2885**	1.2294	5 %	**1.3317**	1.2353	8 %
Edmonton par oil ($/bbl)	**54.78**	67.72	(19)%	**47.80**	59.84	(20)%
AECO natural gas price ($/mcf)[4]	**1.25**	2.67	(53)%	**1.68**	2.81	(40)%
NYMEX natural gas price (US$/mmbtu)[5]	**1.95**	2.64	(26)%	**2.02**	2.81	(28)%

(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 June 30					
	2016			2015		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 30.09**	**$ —**	**$ 30.09**	$ 44.59	$ —	$ 44.59
Light oil and condensate ($/bbl)	**47.24**	**52.79**	**52.42**	62.20	65.34	65.11
NGL ($/bbl)	**18.56**	**12.50**	**13.28**	23.05	14.67	15.78
Natural gas ($/mcf)	**1.30**	**2.39**	**1.94**	2.61	3.43	3.06
Weighted average ($/boe)[2]	**$ 25.80**	**$ 34.43**	**$ 30.52**	$ 40.43	$ 46.67	$ 43.34

	Six Months Ended June 30					
	2016			2015		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 20.87**	**$ —**	**$ 20.87**	$ 36.21	$ —	$ 36.21
Light oil and condensate ($/bbl)	**41.37**	**45.03**	**44.79**	54.72	58.81	58.50
NGL ($/bbl)	**17.72**	**15.59**	**15.86**	23.65	16.55	17.55
Natural gas ($/mcf)	**1.62**	**2.57**	**2.17**	2.64	3.56	3.14
Weighted average ($/boe)[2]	**$ 19.40**	**$ 31.63**	**$ 26.06**	$ 33.70	$ 43.71	$ 38.30

(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 Q2/2016 was $52.79/bbl, down 19% from $65.34/bbl in Q2/2015, which is slightly less than the 22% decrease in the LLS benchmark (expressed in Canadian dollars). U.S. light oil and condensate pricing for YTD 2016 was $45.03/bbl, down 23% from $58.81/bbl in YTD 2015 also slightly less than the 24% decrease in the LLS benchmark (expressed in Canadian dollars). Reduced supply along with increased pipeline capacity have tightened the pricing differential between our U.S. light oil and condensate to LLS during 2016.

During Q2/2016, our Canadian average sales price for light oil and condensate was $47.24/bbl, down 24% from $62.20/bbl in Q2/2015, as compared to a 19% decrease in the benchmark Edmonton par price. Canadian light oil and condensate pricing was $41.37/bbl for YTD 2016 compared to $54.72/bbl for YTD 2015, a 24% decrease compared to a 20% 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 Q2/2016 was $30.09/bbl, a $14.50/bbl decrease from Q2/2015. YTD 2016, our realized heavy oil price was $20.87/bbl, a $15.34/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 $15.37/bbl for Q2/2016 and by $15.28/bbl for YTD 2016 as our heavy oil is generally sold at a fixed dollar differential to the benchmark. Our price decreased slightly less than the benchmark during 2016 as the volumes shut-in have a higher discount to the benchmark price resulting in better price realizations in 2016.

Our Canadian average realized natural gas price for the three and six months ended June 30, 2016 was $1.30/mcf and $1.62/mcf, respectively, down 50% and 38% from the same periods in 2015. The decrease in our realized price was consistent with the decrease in the AECO benchmarks for the three and six months ended June 30, 2016 of 53% and 40% from the same periods in 2015.

Our U.S. average realized natural gas price for the three and six months ended June 30, 2016 was $2.39/mcf and $2.57/mcf, respectively, down 30% and 28% from the same periods of 2015. The decrease in the U.S. average realized natural gas price was consistent with the decrease in the NYMEX benchmark for the three and six months ended June 30, 2016 of 26% and 28% for the same periods of 2015.

Our realized NGL price was $13.28/bbl or 23% of WTI (expressed in Canadian dollars) in Q2/2016 compared to $15.78/bbl or 22% of WTI (expressed in Canadian dollars) in Q2/2015. For YTD 2016, our realized NGL price was 30% of WTI (expressed in Canadian dollars) which is slightly higher than 27% of WTI in YTD 2015. In Q2/2016, the operator of our Eagle Ford assets reversed the changes to certain post-production NGL processing arrangements that were recorded in Q1/2016 which reduced NGL revenues and operating expenses in Q2/2016 but have no impact on YTD 2016.

Gross Revenues

	Three Months Ended June 30					
	2016			2015		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 61,396**	**$ —**	**$ 61,396**	$ 143,626	$ —	$ 143,626
Light oil and condensate	**6,279**	**98,162**	**104,441**	10,752	142,686	153,438
NGL	**2,141**	**9,744**	**11,885**	2,276	9,542	11,818
Total liquids revenue	**69,816**	**107,906**	**177,722**	156,654	152,228	308,882
Natural gas revenue	**4,673**	**12,131**	**16,804**	9,736	15,723	25,459
Total oil and natural gas revenue	**74,489**	**120,037**	**194,526**	166,390	167,951	334,341
Heavy oil blending revenue	**1,207**	**—**	**1,207**	8,462	—	8,462
Total petroleum and natural gas revenues	**$ 75,696**	**$ 120,037**	**$ 195,733**	$ 174,852	$ 167,951	$ 342,803

Six Months Ended June 30						
	2016			2015		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 89,703**	**$ —**	**$ 89,703**	$ 244,482	$ —	$ 244,482
Light oil and condensate	**11,393**	**177,667**	**189,060**	19,752	265,843	285,595
NGL	**4,196**	**24,593**	**28,789**	4,972	21,167	26,139
Total liquids revenue	**105,292**	**202,260**	**307,552**	269,206	287,010	556,216
Natural gas revenue	**11,986**	**26,227**	**38,213**	19,922	31,912	51,834
Total oil and natural gas revenue	**117,278**	**228,487**	**345,765**	289,128	318,922	608,050
Heavy oil blending revenue	**3,566**	**—**	**3,566**	18,136	—	18,136
Total petroleum and natural gas revenues	**$ 120,844**	**$ 228,487**	**$ 349,331**	$ 307,264	$ 318,922	$ 626,186

Total petroleum and natural gas revenues for Q2/2016 of $195.7 million decreased $147.1 million from Q2/2015 with lower commodity prices contributing $82.1 million of the decrease and the remaining $65.0 million from lower production volumes. Petroleum and natural gas revenues of $120.0 million in the U.S. decreased $47.9 million from Q2/2015 due to a decrease in realized prices on all products. In Canada, petroleum and natural gas revenues for Q2/2016 totaled $75.7 million, a $99.2 million decrease compared to Q2/2015 due to lower realized prices and lower production volumes.

Total petroleum and natural gas revenues for YTD 2016 of $349.3 million decreased $276.9 million from YTD 2015 with lower commodity prices contributing $163.3 million of the decrease and the remaining $113.6 million from lower production volumes. Petroleum and natural gas revenues of $228.5 million in the U.S. decreased $90.4 million from YTD 2015 mainly due to a decrease in realized prices on all products. In Canada, petroleum and natural gas revenues for YTD 2016 totaled $120.8 million, a $186.4 million decrease compared to YTD 2015 due to lower realized prices and lower production volumes.

Heavy oil blending revenue of $1.2 million and $3.6 million for the three and six months ended June 30, 2016, respectively, decreased $7.3 million and $14.6 million compared to the same periods in 2015. Heavy oil blending revenue decreased in 2016 as the Company sold less diluent with the decrease in heavy oil production in Canada. Heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. The cost of blending diluent is recovered in the sale price of the blended product. Our heavy oil transported by rail does not require blending diluent. The purchases and sales of blending diluent are recorded as heavy oil blending expense and revenue, respectively.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2016 and 2015.

Three Months Ended June 30						
	2016			2015		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 7,920**	**$ 34,466**	**$ 42,386**	$ 28,258	$ 49,628	$ 77,886
Average royalty rate[(1)]	**10.6%**	**28.7%**	**21.8%**	17.0%	29.5%	23.3%
Royalty rate per boe	**$ 2.74**	**$ 9.89**	**$ 6.65**	$ 6.87	$ 13.79	$ 10.10

Six Months Ended June 30						
	2016			2015		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 11,755**	**$ 65,213**	**$ 76,968**	$ 41,677	$ 92,916	$ 134,593
Average royalty rate[(1)]	**10.0%**	**28.5%**	**22.3%**	14.4%	29.1%	22.1%
Royalty rate per boe	**$ 1.94**	**$ 9.03**	**$ 5.80**	$ 4.86	$ 12.74	$ 8.48

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

Total royalties for Q2/2016 of $42.4 million decreased 46%, or $35.5 million, from Q2/2015, due to the decline in gross revenues. The overall royalty rate in Q2/2016 of 21.8% was slightly lower than 23.3% in Q2/2015. The royalty rate decreased slightly as the royalty rate in Canada was lower in Q2/2016 as a result of lower prices. Canadian royalties decreased to 10.6% of revenue for Q2/2016, compared to 17.0% of revenue in Q2/2015. Canadian crown royalty rates are partially based on price and with the lower commodity prices experienced during Q2/2016, the Company recorded lower crown royalty rates compared to Q2/2015. The royalty percentage on our U.S. assets does not vary with price and as a result the U.S. royalty rate in Q2/2016 of 28.7% has remained fairly consistent with the Q2/2015 rate of 29.5% and overall royalties have decreased with the decrease in gross revenues.

Total royalties for YTD 2016 of $77.0 million decreased 43%, or $57.6 million, from YTD 2015, due to the decline in gross revenues. The overall royalty rate in YTD 2016 of 22.3% 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 10.0% of revenue for YTD 2016, compared to 14.4% 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 28.5% has remained consistent with the YTD 2015 rate of 29.1% and overall royalties have decreased with the decrease in gross revenues.

Operating Expenses

	Three Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expenses	**$ 31,280**	**$ 23,995**	**$ 55,275**	$ 55,341	$ 26,739	$ 82,080
Operating expenses per boe	**$ 10.84**	**$ 6.88**	**$ 8.67**	$ 13.45	$ 7.43	$ 10.64

	Six Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expenses	**$ 65,925**	**$ 59,030**	**$ 124,955**	$ 115,915	$ 53,920	$ 169,835
Operating expenses per boe	**$ 10.91**	**$ 8.17**	**$ 9.42**	$ 13.51	$ 7.39	$ 10.70

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

Operating expenses of $55.3 million and $125.0 million for the three and six months ended June 30, 2016, respectively, decreased by $26.8 million and $44.9 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 $8.67/boe and $9.42/boe for the three and six months ended June 30, 2016, respectively, compared to $10.64/boe and $10.70/boe for the same periods in 2015. The lower cost Eagle Ford assets comprise a larger proportion of our overall volumes which is helping to reduce our overall operating costs per boe. In Canada, we are also seeing the impacts of our cost savings initiatives along with the benefit of shutting-in higher cost properties as our operating expenses per unit of production were lower in the three and six months ended June 30, 2016 compared to same periods in 2015.

U.S. operating expenses of $24.0 million for Q2/2016 decreased $2.7 million compared to Q2/2015. In Q1/2016, the operator of the Eagle Ford property changed certain post-production processing arrangements which increased operating expenses and revenues. In Q2/2016, this change was reversed by the operator resulting in a decrease to operating expenses and revenues. The reversal of the post production processing arrangement reduced operating costs by approximately $1.00/boe in Q2/2016 with no impact on the YTD 2016. On a unit of production basis, YTD 2016 operating expenses were $8.17/boe compared to $7.39/boe in YTD 2015 representing an increase of $0.78/boe. This increase in per unit costs in the U.S is primarily a result of the weaker Canadian dollar against the U.S. dollar. Operating expenses per boe in U.S. dollars for YTD 2016 have averaged US$6.17/boe which is comparable to YTD 2015 costs of US$5.98/boe.

Canadian operating expenses of $31.3 million and $65.9 million for the three and six months ended June 30, 2016, respectively, decreased $24.1 million and $50.0 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 $10.84/boe and $10.91/boe for the three and six months ended June 30, 2016, respectively, compared to $13.45/boe and $13.51/boe for the same periods in 2015 reflecting the cost savings initiatives during 2016 and the impact of high cost production being shut-in for part of YTD 2016. As commodity prices improve and the higher cost shut-in volumes are restored, we expect Canadian operating expenses, on a unit of production basis, to increase.

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 six months ended June 30, 2016 and 2015.

	Three Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expenses	**$ 5,146**	**$ —**	**$ 5,146**	$ 14,928	$ —	$ 14,928
Transportation expense per boe	**$ 1.78**	**$ —**	**$ 0.81**	$ 3.63	$ —	$ 1.94

	Six Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expenses	**$ 11,921**	**$ —**	**$ 11,921**	$ 30,876	$ —	$ 30,876
Transportation expense per boe	**$ 1.97**	**$ —**	**$ 0.90**	$ 3.60	$ —	$ 1.94

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

Transportation expenses for the three and six months ended June 30, 2016 totaled $5.1 million and $11.9 million, respectively, a decrease of 66% and 61% 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, costs have decreased as a large portion of the shut-in volumes were subject to higher transportation charges.

Blending Expenses

Blending expenses for the three and six months ended June 30, 2016 of $1.2 million and $3.6 million, respectively, have decreased compared to $8.5 million and $18.1 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 six months ended June 30, 2016 and 2015.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2016**	2015	Change	**2016**	2015	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 18,778**	$ 48,784	$ (30,006)	**$ 60,270**	$ 156,811	$ (96,541)
Natural gas	**5,038**	309	4,729	**8,172**	6,037	2,135
Foreign currency	**—**	(9,021)	9,021	**—**	(20,942)	20,942
Total	**$ 23,816**	$ 40,072	$ (16,256)	**$ 68,442**	$ 141,906	$ (73,464)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (64,539)**	$ (59,545)	$ (4,994)	**$ (99,526)**	$ (129,124)	$ 29,598
Natural gas	**(16,025)**	351	(16,376)	**(11,161)**	(4,647)	(6,514)
Foreign currency	**—**	14,036	(14,036)	**—**	(1,420)	1,420
Interest and financing(1)	**—**	3,419	(3,419)	**—**	5,280	(5,280)
Total	**$ (80,564)**	$ (41,739)	$ (38,825)	**$ (110,687)**	$ (129,911)	$ 19,224
Total financial derivatives gain (loss)						
Crude oil	**$ (45,761)**	$ (10,761)	$ (35,000)	**$ (39,256)**	$ 27,687	$ (66,943)
Natural gas	**(10,987)**	660	(11,647)	**(2,989)**	1,390	(4,379)
Foreign currency	**—**	5,015	(5,015)	**—**	(22,362)	22,362
Interest and financing	**—**	3,419	(3,419)	**—**	5,280	(5,280)
Total	**$ (56,748)**	$ (1,667)	$ (55,081)	**$ (42,245)**	$ 11,995	$ (54,240)

(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 $23.8 million and $68.4 million for three and six months ended June 30, 2016, respectively, relate mainly to crude oil prices being at levels below those set in our fixed price contracts.

The unrealized financial derivatives loss of $80.6 million for Q2/2016 is due to the increase in WTI price at June 30, 2016 as compared to March 31, 2016 and the realization, or reversal, of previous unrealized gains recorded at March 31, 2016. The unrealized financial derivatives loss of $110.7 million for YTD 2016 is due to the increase in WTI price at June 30, 2016 as compared to December 31, 2015 and the realization, or reversal, of previous unrealized gains recorded at December 31, 2015

A summary of the financial derivative contracts in place as at June 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 June 30					
	2016			2015		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**31,722**	**38,309**	**70,031**	45,222	39,548	84,770
Operating netback:						
Oil and natural gas revenues	**$ 25.80**	**$ 34.43**	**$ 30.52**	$ 40.43	$ 46.67	$ 43.34
Less:						
Royalties	**2.74**	**9.89**	**6.65**	6.87	13.79	10.10
Operating expenses	**10.84**	**6.88**	**8.67**	13.45	7.43	10.64
Transportation expenses	**1.78**	**—**	**0.81**	3.63	—	1.94
Operating netback	**$ 10.44**	**$ 17.66**	**$ 14.39**	$ 16.48	$ 25.45	$ 20.66
Realized financial derivatives gain	**—**	**—**	**3.74**	—	—	5.19
Operating netback after financial derivatives	**$ 10.44**	**$ 17.66**	**$ 18.13**	$ 16.48	$ 25.45	$ 25.85

	Six Months Ended June 30					
	2016			2015		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**33,214**	**39,688**	**72,902**	47,400	40,307	87,707
Operating netback:						
Oil and natural gas revenues	**$ 19.40**	**$ 31.63**	**$ 26.06**	$ 33.70	$ 43.71	$ 38.30
Less:						
Royalties	**1.94**	**9.03**	**5.80**	4.86	12.74	8.48
Operating expenses	**10.91**	**8.17**	**9.42**	13.51	7.39	10.70
Transportation expenses	**1.97**	**—**	**0.90**	3.60	—	1.94
Operating netback	**$ 4.58**	**$ 14.43**	**$ 9.94**	$ 11.73	$ 23.58	$ 17.18
Realized financial derivatives gain	**—**	**—**	**5.16**	—	—	8.94
Operating netback after financial derivatives	**$ 4.58**	**$ 14.43**	**$ 15.10**	$ 11.73	$ 23.58	$ 26.12

Exploration and Evaluation Expense

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

Exploration and evaluation expense decreased to $1.9 million for Q2/2016 from $2.2 million in Q2/2015. Exploration and evaluation expense decreased to $3.4 million for YTD 2016 from $4.5 million for YTD 2015. The decrease is due to lower expiries of undeveloped land.

Depletion and Depreciation

	Three Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[1]	**$ 46,843**	**$ 74,470**	**$ 121,940**	$ 67,711	$ 92,820	$ 161,476
Depletion and depreciation per boe	**$ 16.23**	**$ 21.36**	**$ 19.13**	$ 16.45	$ 25.79	$ 20.93

	Six Months Ended June 30					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[1]	**$ 101,628**	**$ 160,609**	**$ 263,611**	$ 142,828	$ 191,204	$ 335,603
Depletion and depreciation per boe	**$ 16.81**	**$ 22.24**	**$ 19.87**	$ 16.65	$ 26.21	$ 21.14

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $121.9 million and $263.6 million for the three and six months ended June 30, 2016, respectively, decreased by $39.5 million and $72.0 million from the same periods in 2015. On a per boe basis, depletion and depreciation expense for the three and six months ended June 30, 2016 of $19.13/boe and $19.87/boe, respectively, decreased from $20.93/boe and $21.14/boe for the same periods in 2015. The depletion rate decreased during 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 for 2016.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2016**	2015	Change	**2016**	2015	Change
General and administrative expenses	**$ 12,233**	$ 15,557	(21)%	**$ 26,402**	$ 32,612	(19)%
General and administrative expenses per boe	**$ 1.92**	$ 2.02	(5)%	**$ 1.99**	$ 2.05	(3)%

General and administrative expenses for the three and six months ended June 30, 2016 of $12.2 million and $26.4 million, respectively, decreased from $15.6 million and $32.6 million for the same periods in 2015. The decreases are attributable to reductions in staffing levels commensurate with lower activity levels combined with a reduction in discretionary spending.

Share-Based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in 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 $3.9 million and $8.4 million for the three and six months ended June 30, 2016, respectively, compared to $8.2 million and $16.2 million for the same periods in 2015. The decrease in share-based compensation expense for both periods is a result of a lower fair value of share awards granted due to a reduction in the Company's share price at grant date for new grants in 2016.

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 $1.1 million to $27.9 million for Q2/2016, compared to $26.8 million in Q2/2015. The Canadian dollar was weaker in Q2/2016 compared to Q2/2015 which increased our interest expense on our long-term notes as the majority of our long-term notes are denominated in U.S. dollars.

Financing and interest expenses increased slightly to $56.9 million for YTD 2016, compared to $56.2 million in YTD 2015. Interest on long-term notes increased to $45.3 million during YTD 2016 compared to $43.4 million in YTD 2015 as the Canadian dollar was weaker against the U.S. dollar in YTD 2016 compared to YTD 2015 which increased our interest expense as a majority of our long-term notes are denominated in U.S. dollars. This was offset by lower interest charges on our bank loan in 2016 as compared to 2015 as we had larger bank loans in 2015 before the proceeds from the equity financing on April 2, 2015, were used to reduce bank indebtedness.

Foreign Exchange

Unrealized foreign exchange gains and losses are recognized with 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 and a strengthening Canadian dollar against the U.S. dollar from current period to previous period will result in unrealized gains and a weakening Canadian dollar will result in unrealized losses. 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 June 30			Six Months Ended June 30		
($ thousands except for % and exchange rates)	**2016**	2015	Change	**2016**	2015	Change
Unrealized foreign exchange loss (gain)	**$ 3,549**	$ (18,349)	(119)%	**$ (83,252)**	$ 82,967	(200)%
Realized foreign exchange (gain) loss	**(222)**	4,374	(105)%	**(764)**	113	(776)%
Foreign exchange loss (gain)	**$ 3,327**	$ (13,975)	(124)%	**$ (84,016)**	$ 83,080	(201)%
CAD/USD exchange rates:						
At beginning of period	**1.2971**	1.2683		**1.3840**	1.1601	
At end of period	**1.3009**	1.2474		**1.3009**	1.2474	

The Company recorded unrealized foreign exchange loss of $3.5 million for Q2/2016 as the Canadian dollar weakened against the U.S. dollar at June 30, 2016 as compared to March 31, 2016. The Company recorded unrealized foreign exchange gain of $83.3 million for YTD 2016 as the Canadian dollar strengthened against the U.S. dollar at June 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 six months ended June 30, 2016, the Company recorded realized foreign exchange gains of $0.2 million and $0.8 million, respectively.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2016**	2015	Change	**2016**	2015	Change
Current income tax (recovery) expense	**$ (2,284)**	$ (553)	$ (1,731)	**$ (3,726)**	$ 16,382	$ (20,108)
Deferred income tax (recovery)	**(46,783)**	(12,313)	(34,470)	**(94,905)**	(53,995)	(40,910)
Total income tax (recovery)	**$ (49,067)**	$ (12,866)	$ (36,201)	**$ (98,631)**	$ (37,613)	$ (61,018)

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 Q2/2016, this resulted in a current income tax recovery of $2.3 million, an increase of $1.7 million over the current income tax recovery of $0.6 million in Q2/2015. For YTD 2016, this resulted in a current income tax recovery of $3.7 million, an increase of $20.1 million over the current income tax expense of $16.4 million in YTD 2015.

The deferred income tax recovery of $46.8 million for Q2/2016 increased $34.5 million from $12.3 million for Q2/2015. The deferred income tax recovery of $94.9 million for YTD 2016 increased $40.9 million from $54.0 million for YTD 2015. The increase for both periods is primarily the result of 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 will vigorously defend our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

We will file 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 Q2/2016 totaled $86.9 million ($0.41 per basic and diluted share) compared to net loss of $27.0 million ($0.13 per basic and diluted share) for Q2/2015. Net loss for YTD 2016 totaled $86.3 million ($0.41 per basic and diluted share) compared to net loss of $202.9 million ($1.08 per basic and diluted share) for YTD 2015. Funds from operations for Q2/2016 totaled $81.3 million ($0.39 per basic and diluted share) as compared to $158.1 million ($0.60 per basic and diluted share) for Q2/2015. Funds from operations for YTD 2016 totaled $126.9 million ($0.60 per basic and diluted share) as compared to $318.3 million ($1.70 per basic and diluted share) for YTD 2015. The components of the change in net income (loss) and funds from operations from Q2/2015 to Q2/2016 and YTD 2015 to YTD 2016 are detailed in the following table:

	Three months ended June 30		Six months ended June 30	
($ thousands)	**Net income (loss)**	**Funds from operations**	**Net income (loss)**	**Funds from operations**
2015	$ (26,955)	$ 158,050	$ (202,871)	$ 318,270
Increase (decrease) in revenues				
Revenue, net of royalties	(111,570)	(111,570)	(219,230)	(219,230)
(Increase) decrease in expenses				
Operating	26,805	26,805	44,880	44,880
Transportation	9,782	9,782	18,955	18,955
Blending	7,255	7,255	14,570	14,570
General and administrative	3,324	3,324	6,210	6,210
Exploration and evaluation	299	—	1,187	—
Depletion and depreciation	39,536	—	71,992	—
Share-based compensation	4,296	—	7,860	—
Financing and interest	(1,116)	(69)	(759)	536
Financial derivatives	(55,081)	(16,256)	(54,240)	(73,464)
Foreign exchange	(17,302)	4,596	167,096	877
Other(1)(2)	(2,411)	(2,387)	(2,998)	(4,806)
Current income tax	1,731	1,731	20,108	20,108
Deferred income tax	34,470	—	40,910	—
2016	**$ (86,937)**	**$ 81,261**	**$ (86,330)**	**$ 126,906**

(1) For net income (loss), other includes gain (loss) on disposition and other expense.
(2) For funds from operations, other includes other expense.

Dividends

In 2015, we declared monthly dividends of $0.10 per common share for January to June totaling $0.60 per common share. The Company paid $83.2 million in cash dividends in YTD 2015, and $25.5 million of dividends declared were settled by issuing 1,262,000 common shares under the Company's dividend reinvestment plan. In response to the prolonged low price commodity environment and in an effort to preserve liquidity, Baytex suspended the monthly dividend effective September 2015.

Other Comprehensive Income (Loss)

Other comprehensive income (loss) is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $6.1 million foreign currency translation gain for Q2/2016 is due to a slight weakening of the Canadian dollar against the U.S. dollar at June 30, 2016 as compared to March 31, 2016. The $152.6 million foreign currency translation loss for YTD 2016 is due to the strengthening of the Canadian dollar against the U.S. dollar at June 30, 2016 as compared to December 31, 2015.

Capital Expenditures

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

	Three Months Ended June 30, 2016					
	2016			2015		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 1,374**	**$ 6,097**	**$ 7,471**	$ (656)	$ (156)	$ (812)
Seismic	**58**	**—**	**58**	73	—	73
Drilling, completion and equipping	**378**	**26,285**	**26,663**	4,299	82,255	86,554
Facilities	**937**	**361**	**1,298**	3,974	16,221	20,195
Total exploration and development	**$ 2,747**	**$ 32,743**	**$ 35,490**	$ 7,690	$ 98,320	$ 106,010
Total acquisitions, net of divestitures	**(37)**	**—**	**(37)**	1,410	(240)	1,170
Total oil and natural gas expenditures	**$ 2,710**	**$ 32,743**	**$ 35,453**	$ 9,100	$ 98,080	$ 107,180
Wells drilled (net)	**—**	**11.3**	**11.3**	2.0	13.2	15.2

	Six Months Ended June 30, 2016					
	2016			2015		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 2,237**	**$ 6,097**	**$ 8,334**	$ 2,800	$ (3)	$ 2,797
Seismic	**113**	**—**	**113**	132	—	132
Drilling, completion and equipping	**3,810**	**95,966**	**99,776**	15,525	203,252	218,777
Facilities	**1,445**	**7,507**	**8,952**	10,505	21,228	31,733
Total exploration and development	**$ 7,605**	**$ 109,570**	**$ 117,175**	$ 28,962	$ 224,477	$ 253,439
Total acquisitions, net of divestitures	**(46)**	**—**	**(46)**	2,821	(101)	2,720
Total oil and natural gas expenditures	**$ 7,559**	**$ 109,570**	**$ 117,129**	$ 31,783	$ 224,376	$ 256,159
Wells drilled (net)	**1.0**	**23.8**	**24.8**	11.1	29.1	40.2

YTD 2016 capital expenditures totaled $117.1 million as compared to $256.2 million in YTD 2015. Capital spending has been focused on our Eagle Ford assets with YTD 2016 capital spending of $109.6 million down from $224.4 million for YTD 2015. The decrease in spending is from lower activity levels with lower commodity prices and from 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$5.4 million as compared to US$8.2 million in 2014. We also recognized additional savings on drilling, completion and equipping expenditures in Q2/2016 as actual costs incurred were less than previously estimated. In Canada, we have drilled one well in YTD 2016 and have spent $7.6 million compared to YTD 2015 where we drilled 11.1 net wells and spent $29.0 million. Despite achieving cost reductions of approximately 20% in Canada during 2015, the prevailing commodity prices have not supported additional drilling on our Canadian assets.

In Q2/2016, our capital expenditures totaled $35.5 million compared to $107.2 million in Q2/2015 and were focused on our Eagle Ford assets with 92% of the total capital being spent in the U.S. The significant reduction year over year 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 Q2/2016 as actual costs incurred were less than previously estimated. We did not drill any wells in Canada and spent $2.7 million in Q2/2016 as compared to 2.0 net wells and $7.7 million in Q2/2015.

Subsequent to the end of the quarter, we closed the sale of our operated assets in the Eagle Ford on July 27, 2016 for approximately $55 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 33% 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 the current commodity price environment continues, or if prices decline further, we may need to make additional changes to our capital program. A sustained low price environment could lead to a default of certain financial covenants, which could impact our ability to borrow under existing credit facilities or obtain new financing. It could also restrict our ability to pay future dividends or sell assets and may result in our debt becoming immediately due and payable. Should our internally generated funds from operations be insufficient to fund the capital expenditures required to maintain operations, we may draw additional funds from our current credit facilities or we may consider seeking additional capital in the form of debt or equity. There is also no certainty that any of the additional sources of capital would be available when required.

At June 30, 2016, net debt was $1,942.5 million, as compared to $2,049.9 million at December 31, 2015, representing a decrease of $107.4 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 June 30, 2016. Funds from operations exceeded capital spending by $9.7 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 six months ended June 30, 2016 were 3.5%, as compared to 4.0% and 3.1%, respectively, for the same periods in 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 June 30, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at June 30, 2016**	**June 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)	0.86:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage (3) (Minimum Ratio)	4.05:1.00	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 June 30, 2016, our Senior Secured Debt totaled $359 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 expenses, unrealized gains and losses on financial derivatives and foreign exchange and stock based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended June 30, 2016 was $417 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 June 30, 2016 were $103 million.*

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

Long-Term Notes

Baytex has five series of long-term notes outstanding that total $1.54 billion as at June 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 EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at June 30, 2016, the fixed charge coverage ratio was 4.05:1.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These notes as of February 17, 2016 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. The remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, as of April 1, 2016 at specified redemption prices.

Financial Instruments

As part of our normal operations, we are exposed to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default, resulting in the Company incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is partially mitigated through a series of derivative contracts intended to reduce some of the volatility of our funds from operations.

A summary of the risk management contracts in place as at June 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 July 27, 2016, we had 211,541,490 common shares and no preferred shares issued and outstanding. During the three and six months ended June 30, 2016, we issued 25,916 and 131,798 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 June 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	**$ 139,694**	$ 139,694	$ —	$ —	$ —
Bank loan[(1) (2)]	**347,083**	—	347,083	—	—
Long-term notes[(2)]	**1,544,181**	—	—	723,821	820,360
Interest on long-term notes	**420,062**	62,941	125,883	124,789	106,449
Operating leases	**47,985**	8,009	16,404	15,212	8,360
Processing agreements	**50,011**	9,017	9,521	9,043	22,430
Transportation agreements	**68,130**	13,152	22,972	21,969	10,037
Total	**$ 2,617,146**	$ 232,813	$ 521,863	$ 894,834	$ 967,636

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid on such date.
(2) Principal amount of instruments.

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

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 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 six months ended June 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 six months ended June 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 six months ended June 30, 2016.

QUARTERLY FINANCIAL INFORMATION

	2016		2015				2014	
($ thousands, except per common share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Gross revenues	**195,733**	153,598	229,361	265,898	342,792	283,384	465,917	634,400
Net income (loss)	**(86,937)**	607	(412,924)	(517,856)	(26,955)	(175,916)	(361,816)	144,369
Per common share - basic	**(0.41)**	0.00	(1.96)	(2.49)	(0.13)	(1.04)	(2.16)	0.87
Per common share - diluted	**(0.41)**	0.00	(1.96)	(2.49)	(0.13)	(1.04)	(2.16)	0.86

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our expectation for Canadian operating expenses for the remainder of 2016; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the 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.