

## **BAYTEX ENERGY CORP.**

### **Management's Discussion and Analysis**

**For the three and nine months ended September 30, 2015 and 2014**

**Dated November 5, 2015**

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, 2015. This information is provided as of November 5, 2015. 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 third quarter results have been compared with the corresponding period in 2014. 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, 2015, its audited comparative consolidated financial statements for the years ended December 31, 2014 and 2013, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2014. These documents and additional information about Baytex are accessible on the SEDAR website at [www.sedar.com](http://www.sedar.com). All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

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

### **NON-GAAP FINANCIAL MEASURES**

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

#### **Funds from Operations**

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

#### **Payout Ratio**

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

#### **Total Monetary Debt**

We define total monetary debt as the sum of the principal amount of both the long-term debt and the bank loan and working capital surplus or deficit (which is current assets less current liabilities (excluding current financial derivatives)). We believe that this measure assists in providing a more complete understanding of our cash liabilities. See "Liquidity, Capital Resources and Risk Management" for a calculation of total monetary debt.

#### **Operating Netback**

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

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## THIRD QUARTER HIGHLIGHTS

Production for the three months ended September 30, 2015 averaged 82,170 boe/d, a 13% decrease compared to the same period in 2014 due to production declines in Canada as a result of reduced capital spending along with the asset dispositions in 2014. Canadian production was 43,229 boe/d for the third quarter of 2015, representing a decline of 4% from the second quarter of 2015 and a decline of 24% or 13,524 boe/d compared to the third quarter of 2014. For the nine months ended September 30, 2015, production averaged 85,840 boe/d with Canadian production of 45,993 boe/d, down 19% compared to the same period in 2014. Reduced capital spending, property dispositions and shut-in production have contributed to reduced production levels in Canada in 2015. U.S. production of 38,941 boe/d in the third quarter of 2015 was 4% higher than in the third quarter of 2014 with production from the Eagle Ford increasing 15%. This was offset by the North Dakota disposition which closed on September 24, 2014. We anticipate our full year 2015 production will be near the lower end of our guidance of 84,000 to 86,000 boe/d.

The third quarter of 2015 was marked by low commodity prices as West Texas Intermediate oil ("WTI") dipped to a six-year low. The price of WTI averaged US\$46.43/bbl during the third quarter of 2015, a 52% decrease from the same period in 2014. Our hedging contracts and a weaker Canadian dollar mitigated some of the drop in commodity prices. The nine months ended September 30, 2015 was also negatively impacted by declines in commodity pricing resulting in a lower realized price of \$37.10/boe or a decrease of 49% as compared to the same period of 2014. In light of the low commodity prices and in order to maintain financial flexibility we made the difficult decision to suspend our monthly dividend in September and further reduced our heavy oil capital program in Canada.

We reduced capital spending in the third quarter of 2015 to \$126.8 million, down \$103.2 million from the \$230.0 million spent in the third quarter of 2014. This reduction is directly attributable to the drop in commodity prices. We invested \$33.5 million in Canada during the third quarter which is down \$43.1 million from the same period in 2014. Despite negotiated cost reductions from service providers, the current commodity prices do not support further drilling resulting in a deferral of the heavy oil capital program in Canada. In the third quarter of 2015, \$93.3 million, or 74% of our capital spending was directed to the Eagle Ford assets. The third quarter capital investment program in the Eagle Ford was down from \$98.3 million in the second quarter of 2015 and \$140.3 million in the third quarter of 2014. We anticipate our full year 2015 capital expenditures will be toward the lower end of our guidance of \$500 to \$575 million.

Funds from operations ("FFO") for the three and nine months ended September 30, 2015 were \$105.1 million and \$423.3 million, respectively, compared to \$298.0 million and \$634.3 million, for the same periods of 2014. The decrease in FFO is due to both lower commodity prices and lower production volumes.

During the quarter, we recorded an impairment charge of \$493.2 million on our Eagle Ford operations. The impairment charge is directly attributable to the decline in commodity prices as the acquired assets were recorded at their fair values when the WTI price was more than US\$100/bbl.

## 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 Bakken assets in North Dakota up to the date of disposition on September 24, 2014 and the Eagle Ford assets in Texas subsequent to the date of acquisition on June 11, 2014.

### Production

Three Months Ended September 30						
Daily Production	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	33,639	—	33,639	45,500	—	45,500
Light oil and condensate	1,729	22,983	24,712	2,628	25,496	28,124
NGL	985	7,522	8,507	1,174	5,455	6,629
Total liquids (bbl/d)	36,353	30,505	66,858	49,302	30,951	80,253
Natural gas (mcf/d)	41,256	50,613	91,869	44,703	38,597	83,300
Total production (boe/d)	43,229	38,941	82,170	56,753	37,384	94,137
<b>Production Mix</b>						
Heavy oil	77%	—%	40%	80%	—%	48%
Light oil and condensate	4%	59%	30%	5%	68%	30%
NGL	3%	19%	11%	2%	15%	7%
Natural gas	16%	22%	19%	13%	17%	15%

Nine Months Ended September 30						
Daily Production	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	36,067	—	36,067	45,641	—	45,641
Light oil and condensate	1,905	24,305	26,210	2,664	11,905	14,569
NGL	1,102	7,220	8,322	1,461	2,253	3,714
Total liquids (bbl/d)	39,074	31,525	70,599	49,766	14,158	63,924
Natural gas (mcf/d)	41,514	49,934	91,448	43,033	15,733	58,766
Total production (boe/d)	45,993	39,847	85,840	56,938	16,780	73,718
<b>Production Mix</b>						
Heavy oil	79%	—%	41%	79%	—%	61%
Light oil and condensate	4%	62%	31%	5%	71%	21%
NGL	2%	18%	10%	3%	13%	5%
Natural gas	15%	20%	18%	13%	16%	13%

Total production for the three months ended September 30, 2015 averaged 82,170 boe/d, a decrease of 13% compared to the same period in 2014. Production in Canada decreased 24% compared to prior period, to 43,229 boe/d, with declines from reduced capital spending and approximately 3,000 boe/d from non-core dispositions and uneconomic production we have shut-in. At September 30, 2015, we had approximately 2,400 boe/d of uneconomic production shut-in. U.S. production for the three months ended September 30, 2015 increased 4% to 38,941 boe/d, as production in the Eagle Ford increased 15% due to our ongoing development program. This was partially offset by the disposition of the North Dakota assets on September 24, 2014.

Production for the nine months ended September 30, 2015 averaged 85,840 boe/d, an increase of 16% compared to the same period in 2014. The overall increase is due to the acquisition of the Eagle Ford assets in June of 2014 which outweighed the non-core dispositions and production declines in Canada. Canadian production for the nine months ended September 30, 2015 decreased 19%, to 45,993 boe/d compared to 56,938 boe/d in 2014. This reduction is due to reduced capital spending over the prior period combined with non-core dispositions in late 2014 and uneconomic production we have shut-in which lowered average production by approximately 2,500 boe/d. U.S. production for the nine months ended September 30, 2015 was 39,847 boe/d, an increase of 137% over the prior period as the Eagle Ford production is included for the full nine months during 2015 and was only included from June 11, 2014 for 2014. This was offset by the divestiture of the North Dakota production which produced 3,326 boe/d for the nine months ended September 30, 2014.

## 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 the three months ended September 30, 2015, the price of WTI averaged US\$46.43/bbl, a 52% decrease from the average WTI price of US\$97.17/bbl in the third quarter of 2014 and a 20% decrease from US\$57.94/bbl in the second quarter of 2015. For the nine months ended September 30, 2015, the price of WTI averaged US\$51.00/bbl, a 49% decrease from the average WTI price of US\$99.61/bbl for the same period in 2014. The low prices experienced during the three and nine months ended September 30, 2015, as compared to the same periods in 2014, was brought on by the ongoing global over supply of oil stemming from high North American production growth and the decision by the Organization of Petroleum Exporting Countries (OPEC) to step away from its role as the swing producer.

The discount for Canadian heavy oil is measured by the WCS price differential between WTI and Western Canadian Select ("WCS") heavy oil. For the three and nine months ended September 30, 2015, the WCS heavy oil differential averaged US\$13.30/bbl and US\$13.20/bbl, respectively, down from US\$20.18/bbl and US\$21.11/bbl, for the same periods of 2014. The WCS differential narrowed in the three and nine months ended September 30, 2015 as compared to the same periods in 2014 due to stronger refinery demand for WCS and improved market access. This can be partially attributable to ongoing improvements in rail infrastructure over the past two years and the addition of the Flanagan South pipeline which added approximately 600,000 boe/d of market access in November of 2014.

### Natural Gas

For the three and nine months ended September 30, 2015, the AECO natural gas price averaged \$2.70/mcf and \$2.77/mcf, respectively, as compared to \$4.22/mcf and \$4.55/mcf for the comparative periods of 2014. For the three and nine months ended September 30, 2015, the NYMEX natural gas prices averaged US\$2.77/mmbtu and US\$2.80/mmbtu, respectively, as compared to US\$4.05/mmbtu and US\$4.55/mmbtu the same periods of 2014. The decrease in natural gas prices on both indices during 2015 was driven by historically high production levels.

The following tables compare selected benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2015 and 2014.

	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
<b>Benchmark Averages</b>						
WTI oil (US\$/bbl) <sup>(1)</sup>	\$ 46.43	\$ 97.17	(52)%	\$ 51.00	\$ 99.61	(49)%
WCS heavy oil (US\$/bbl) <sup>(2)</sup>	\$ 33.13	\$ 76.99	(57)%	\$ 37.80	\$ 78.50	(52)%
Heavy oil differential <sup>(3)</sup>	29%	21%		27%	21%	
LLS oil (US\$/bbl) <sup>(4)</sup>	\$ 49.79	\$ 101.93	(51)%	\$ 54.24	\$ 104.55	(48)%
CAD/USD average exchange rate	1.3094	1.0893	20 %	1.2631	1.0940	15 %
Edmonton par oil (\$/bbl)	\$ 56.22	\$ 98.65	(43)%	\$ 58.63	\$ 101.83	(42)%
AECO natural gas price (\$/mcf) <sup>(5)</sup>	\$ 2.70	\$ 4.22	(36)%	\$ 2.77	\$ 4.55	(39)%
NYMEX natural gas price (US\$/mmbtu) <sup>(6)</sup>	\$ 2.77	\$ 4.05	(32)%	\$ 2.80	\$ 4.55	(38)%

(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) Heavy oil differential refers to the WCS discount to WTI on a monthly weighted average basis.

(4) LLS refers to the Argus trade month average.

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

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

Three Months Ended September 30

	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Realized Sales Prices<sup>(1)</sup></b>						
Canadian heavy oil (\$/bbl) <sup>(2)</sup>	\$ 30.90	\$ —	\$ 30.90	\$ 73.99	\$ —	\$ 73.99
Light oil and condensate (\$/bbl)	51.86	55.73	55.46	92.92	100.35	99.65
NGL (\$/bbl)	15.05	15.39	15.35	48.83	34.18	36.77
Natural gas (\$/mcf)	2.72	3.74	3.28	4.19	4.71	4.43
Weighted average (\$/boe) <sup>(2)</sup>	\$ 29.06	\$ 40.72	\$ 34.59	\$ 67.93	\$ 78.28	\$ 72.04

Nine Months Ended September 30

	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Realized Sales Prices<sup>(1)</sup></b>						
Canadian heavy oil (\$/bbl) <sup>(2)</sup>	\$ 34.54	\$ —	\$ 34.54	\$ 74.84	\$ —	\$ 74.84
Light oil and condensate (\$/bbl)	53.84	57.83	57.54	95.91	101.15	100.19
NGL (\$/bbl)	21.06	16.14	16.79	49.36	34.89	40.59
Natural gas (\$/mcf)	2.67	3.62	3.19	4.69	4.85	4.73
Weighted average (\$/boe) <sup>(2)</sup>	\$ 32.23	\$ 42.73	\$ 37.10	\$ 69.29	\$ 80.99	\$ 71.97

(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 production volumes, net of blending costs.

*Average Realized Sales Prices*

Our realized heavy oil price for the three months ended September 30, 2015 was \$30.90/bbl, or 71% of WCS expressed in Canadian dollars, compared to \$73.99/bbl, or 88% of WCS expressed in Canadian dollars in 2014. Our realized heavy oil price for the nine months ended September 30, 2015 was \$34.54/bbl, or 72% of WCS expressed in Canadian dollars, compared to \$74.84/bbl, or 86% of WCS expressed in Canadian dollars in 2014. The Company's decrease in realized heavy oil price of 58% for the three months ended September 30, 2015 and 54% for the nine months ended September 30, 2015 compared to the same periods in 2014 corresponds with the overall decline in global crude oil prices. A portion of the Company's heavy oil is sold at a fixed dollar differential to the WCS benchmark price. Due to the drop in commodity prices, the fixed dollar differential has decreased our realized price as a percentage of WCS.

During the three months ended September 30, 2015, our Canadian average sales price for light oil and condensate was \$51.86/bbl, down 44% from \$92.92/bbl in 2014. This corresponds with the 43% decrease in the benchmark Edmonton Par prices over the same period. U.S. light oil and condensate pricing for the three months ended September 30, 2015 was \$55.73/bbl, down 44% from \$100.35/bbl in the third quarter of 2014, largely in line with the 40% decrease in the LLS benchmark (as expressed in Canadian dollars) over the same period. During the nine months ended September 30, 2015, our Canadian average sales price for light oil and condensate was \$53.84/bbl, down 44% from \$95.91/bbl in 2014, largely in line with the 42% decrease in Edmonton Par price over the same period. U.S. light oil and condensate pricing for the nine months ended September 30, 2015 was \$57.83/bbl, down 43% from \$101.15/bbl in the first nine months of 2014, in line with the 42% decrease in the LLS benchmark (as expressed in Canadian dollars) over the same period.

Our realized natural gas price for the three and nine months ended September 30, 2015 was \$3.28/mcf and \$3.19/mcf, respectively, down from \$4.43/mcf and \$4.73/mcf over the same periods in 2014. This is largely in line with the decreases in the AECO and NYMEX benchmarks during these periods.

## Gross Revenues

(\$ thousands)	Three Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	\$ 95,634	\$ —	\$ 95,634	\$ 309,719	\$ —	\$ 309,719
Light oil and condensate	8,252	117,840	126,092	22,466	235,377	257,843
NGL	1,365	10,647	12,012	5,272	17,150	22,422
Total oil revenue	105,251	128,487	233,738	337,457	252,527	589,984
Natural gas revenue	10,308	17,405	27,713	17,249	16,709	33,958
Total oil and natural gas revenue	115,559	145,892	261,451	354,706	269,236	623,942
Other income	2,746	3	2,749	—	(2)	(2)
Heavy oil blending revenue	4,425	—	4,425	10,475	—	10,475
Total petroleum and natural gas revenues	\$ 122,730	\$ 145,895	\$ 268,625	\$ 365,181	\$ 269,234	\$ 634,415

(\$ thousands)	Nine Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	\$ 340,116	\$ —	\$ 340,116	\$ 932,448	\$ —	\$ 932,448
Light oil and condensate	28,004	383,683	411,687	69,747	328,762	398,509
NGL	6,337	31,814	38,151	19,690	21,461	41,151
Total oil revenue	374,457	415,497	789,954	1,021,885	350,223	1,372,108
Natural gas revenue	30,230	49,317	79,547	55,104	20,812	75,916
Total oil and natural gas revenue	404,687	464,814	869,501	1,076,989	371,035	1,448,024
Other income	7,572	38	7,610	—	413	413
Heavy oil blending revenue	22,561	—	22,561	48,190	—	48,190
Total petroleum and natural gas revenues	\$ 434,820	\$ 464,852	\$ 899,672	\$ 1,125,179	\$ 371,448	\$ 1,496,627

Total petroleum and natural gas revenues for the three months ended September 30, 2015 of \$268.6 million decreased \$365.8 million from the third quarter of 2014. The majority of the decrease from the prior period can be attributed to the drop in commodity prices which accounted for \$283 million of the decrease and lower production volumes which accounted for \$79 million of the decrease. In Canada, petroleum and natural gas revenues for the three months ended September 30, 2015 totaled \$122.7 million, a decrease of \$242.5 million compared to the same period in 2014. This is due to a 57% decrease in realized prices on all products combined with a 24% reduction in production volumes compared to the prior year. Petroleum and natural gas revenues of \$145.9 million in the U.S. decreased \$123.3 million from prior year. This reduction can be attributed to a 48% decrease in realized price and the divestiture of the North Dakota assets which were partially offset by a 15% increase in Eagle Ford production over the period.

Total petroleum and natural gas revenues for the nine months ended September 30, 2015 of \$899.7 million decreased \$597.0 million from the nine months ended September 30, 2014. The majority of the decrease from the prior period can be attributed to the drop in commodity prices which accounted for \$817 million of the decrease, partially offset by higher production volumes contributing \$238 million. In Canada, petroleum and natural gas revenues for the nine months totaled \$434.8 million, a decrease of \$690.4 million compared to the same period in 2014. This is due to a 53% decrease in realized prices on all products combined with a 19% reduction in production volumes. Petroleum and natural gas revenues of \$464.9 million in the U.S. increased \$93.4 million from the prior year due to the acquisition of the Eagle Ford assets offset by the decrease in revenue due to the sale of North Dakota.

Heavy oil blending revenue of \$4.4 million and \$22.6 million for the three and nine months ended September 30, 2015, respectively, decreased \$6.0 million and \$25.6 million, compared to the same periods in 2014. The Company used and sold less diluent during 2015 due to the decrease in heavy oil production within Canada and the increase in transportation by rail which does not require diluent. In addition, the price of blending diluent has declined consistent with the decrease in the price of oil.

## 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 tables summarize our royalties and royalty rates for the three and nine months ended September 30, 2015 and 2014.

Three Months Ended September 30						
(\$ thousands except for % and per boe)	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	\$ 15,445	\$ 42,058	\$ 57,503	\$ 70,231	\$ 80,691	\$ 150,922
Average royalty rate <sup>(1)</sup>	13.4%	28.8%	22.0%	19.8%	30.0%	24.2%
Royalty rate per boe	\$ 3.88	\$ 11.74	\$ 7.61	\$ 13.45	\$ 23.46	\$ 17.43

Nine Months Ended September 30						
(\$ thousands except for % and per boe)	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	\$ 57,122	\$ 134,974	\$ 192,096	\$ 225,458	\$ 112,625	\$ 338,083
Average royalty rate <sup>(1)</sup>	14.1%	29.0%	22.1%	20.9%	30.4%	23.3%
Royalty rate per boe	\$ 4.55	\$ 12.41	\$ 8.20	\$ 14.50	\$ 24.59	\$ 16.80

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

Total royalties for the three months ended September 30, 2015 of \$57.5 million decreased 62%, or \$93.4 million from 2014, due to the declines in revenue and production. Canadian royalties decreased to 13.4% of revenue for the three months ended September 30, 2015, from 19.8% of revenue in 2014. Canadian crown royalty rates are partially based on price. The lower commodity prices experienced during 2015 have resulted in lower crown royalty rates compared to 2014. U.S. royalties for the three months ended September 30, 2015 of \$42.1 million decreased 48%, or \$38.6 million due to lower commodity prices when compared to the same period in 2014. The Eagle Ford royalty rate of 28.8% was comparable to the same period in 2014 as royalty rates for our Eagle Ford assets do not vary with commodity pricing.

Total royalties for the nine months ended September 30, 2015 of \$192.1 million decreased 43%, or \$146.0 million from 2014, mainly due to the decline in revenues. Canadian royalties have decreased to 14.1% of revenue for the nine months ended September 30, 2015, compared to 20.9% of revenue in 2014. Canadian crown royalty rates are partially based on price. The lower commodity prices experienced during 2015 have resulted in lower crown royalty rates compared to 2014. U.S. royalties for the nine months ended September 30, 2015 of \$134.9 million increased 20%, or \$22.3 million due to the inclusion of Eagle Ford for the nine months in 2015. The 2014 period only includes the results of the Eagle Ford assets subsequent to the acquisition on June 11, 2014. Royalty rates for 2015 have decreased to 29.0% compared to 30.4% in the prior period due to the disposition of the North Dakota assets that had a higher royalty rate than the Eagle Ford assets.

## Production and Operating Expenses

Three Months Ended September 30						
(\$ thousands except for per boe)	2015			2014		
	Canada	U.S. <sup>(1)</sup>	Total	Canada	U.S. <sup>(1)</sup>	Total
Production and operating expenses	\$ 48,946	\$ 28,544	\$ 77,490	\$ 66,311	\$ 32,314	\$ 98,625
Production and operating expenses per boe	\$ 12.31	\$ 7.97	\$ 10.25	\$ 12.70	\$ 9.39	\$ 11.39

Nine Months Ended September 30						
(\$ thousands except for per boe)	2015			2014		
	Canada	U.S. <sup>(1)</sup>	Total	Canada	U.S. <sup>(1)</sup>	Total
Production and operating expenses	\$ 164,860	\$ 82,465	\$ 247,325	\$ 198,867	\$ 45,088	\$ 243,955
Production and operating expenses per boe	\$ 13.13	\$ 7.58	\$ 10.55	\$ 12.79	\$ 9.84	\$ 12.12

(1) Production and operating expenses related to the Eagle Ford assets include transportation expenses.

Production and operating expenses were \$77.5 million and \$247.3 million for the three and nine months ended September 30, 2015, respectively, representing a decrease of \$21.1 million and an increase of \$3.4 million compared to the same periods in 2014. On a per boe basis, production and operating expenses for the three and nine months ended September 30, 2015 decreased to \$10.25/boe and \$10.55/boe, respectively, compared to \$11.39/boe and \$12.12/boe for the same periods in 2014. Production and operating per boe costs have decreased from the prior period due to cost saving initiatives across all our operations combined with the addition of the Eagle Ford assets which have lower costs and comprise a larger percentage of our total production in 2015 as compared to 2014.

Canadian production and operating expenses of \$48.9 million and \$164.9 million for the three and nine months ended September 30, 2015 decreased \$17.4 million and \$34.0 million compared to the same periods in 2014. These decreases are a result of lower production volumes and realized cost savings on our operations. Canadian production and operating expenses per boe decreased \$0.39/boe for the three months ended September 30, 2015 compared to the same period in 2014, which reflects the realization of cost saving initiatives. Operating expenses per boe for the nine months ended September 30, 2015 have increased \$0.34/boe compared to the same period in 2014 due to the impact of fixed costs on lower production (as production volumes decrease the cost on a per boe basis increases). However, we are working to mitigate the fixed cost impact through cost saving initiatives.

U.S. production and operating expenses of \$28.5 million and \$82.5 million for the three and nine months ended September 30, 2015, respectively, decreased \$3.8 million and increased \$37.4 million compared to the same periods in 2014. U.S. production and operating expenses per boe decreased \$1.42/boe and \$2.26/boe, for the three and nine months ended September 30, 2015, respectively, which reflects the shift in production to the lower cost Eagle Ford assets compared to our historic North Dakota properties and cost saving initiatives.

### Transportation and Blending Expenses

Transportation expenses include the costs to move production from the field to the sales point. The largest component of transportation expense relates to the movement of heavy oil to pipeline and rail terminals. In order to meet pipeline specifications and to facilitate its marketing, heavy oil transported through pipelines requires blending to reduce its viscosity. 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 following tables compare our transportation and blending expenses for the three and nine months ended September 30, 2015 and 2014.

(\$ thousands except for per boe)	Three Months Ended September 30					
	2015			2014		
	Canada	U.S. <sup>(2)</sup>	Total	Canada	U.S. <sup>(2)</sup>	Total
Blending expenses	\$ 4,424	\$ —	\$ 4,424	\$ 10,475	\$ —	\$ 10,475
Transportation expenses	11,456	—	11,456	20,456	—	20,456
Total transportation and blending expenses	\$ 15,880	\$ —	\$ 15,880	\$ 30,931	\$ —	\$ 30,931
Transportation expenses per boe <sup>(1)</sup>	\$ 2.88	\$ —	\$ 1.52	\$ 3.92	\$ —	\$ 2.36

(\$ thousands except for per boe)	Nine Months Ended September 30					
	2015			2014		
	Canada	U.S. <sup>(2)</sup>	Total	Canada	U.S. <sup>(2)</sup>	Total
Blending expenses	\$ 22,561	\$ —	\$ 22,561	\$ 48,191	\$ —	\$ 48,191
Transportation expenses	42,331	—	42,331	66,228	—	66,228
Total transportation and blending expenses	\$ 64,892	\$ —	\$ 64,892	\$ 114,419	\$ —	\$ 114,419
Transportation expenses per boe <sup>(1)</sup>	\$ 3.37	\$ —	\$ 1.81	\$ 4.26	\$ —	\$ 3.29

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

(2) Transportation expenses related to the Eagle Ford assets are included in production and operating expenses.

Transportation expenses for the three months ended September 30, 2015 totaled \$11.5 million, a decrease of 44%, or \$9.0 million, compared to 2014. Transportation expenses for the nine months ended September 30, 2015 totaled \$42.3 million, a decrease of 36%, or \$23.9 million, compared to 2014. The decreases for both comparative periods are due to lower heavy oil volumes, decreased fuel surcharges and overall cost saving initiatives which includes the increased use of internal trucking.

Blending expenses for the three and nine months ended September 30, 2015 of \$4.4 million and \$22.6 million, respectively, have decreased \$6.1 million and \$25.6 million, compared to the same periods in 2014. Consistent with the decrease in heavy oil blending

revenue, blending expenses decreased due to a decrease in both the price of blending diluent and the volume of blending diluent required.

### 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, 2015 and 2014.

(\$ thousands)	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
<b>Realized financial derivatives gain (loss)</b>						
Crude oil	\$ 36,628	\$ (2,811)	\$ 39,439	\$ 193,439	\$ (13,252)	\$ 206,691
Natural gas	577	45	532	6,614	(1,771)	8,385
Foreign currency	(12,053)	(1,281)	(10,772)	(32,995)	(4,547)	(28,448)
Interest	—	(4,109)	4,109	—	(8,130)	8,130
<b>Total</b>	<b>\$ 25,152</b>	<b>\$ (8,156)</b>	<b>\$ 33,308</b>	<b>\$ 167,058</b>	<b>\$ (27,700)</b>	<b>\$ 194,758</b>
<b>Unrealized financial derivatives gain (loss)</b>						
Crude oil	\$ 36,253	\$ 100,098	\$ (63,845)	\$ (92,871)	\$ 57,752	\$ (150,623)
Natural gas	3,510	2,528	982	(1,137)	287	(1,424)
Foreign currency	3,249	(10,295)	13,544	1,829	(4,177)	6,006
Interest and financing <sup>(1)</sup>	(5,778)	6,357	(12,135)	(498)	22,325	(22,823)
<b>Total</b>	<b>\$ 37,234</b>	<b>\$ 98,688</b>	<b>\$ (61,454)</b>	<b>\$ (92,677)</b>	<b>\$ 76,187</b>	<b>\$ (168,864)</b>
<b>Total financial derivatives gain (loss)</b>						
Crude oil	\$ 72,881	\$ 97,287	\$ (24,406)	\$ 100,568	\$ 44,500	\$ 56,068
Natural gas	4,087	2,573	1,514	5,477	(1,484)	6,961
Foreign currency	(8,804)	(11,576)	2,772	(31,166)	(8,724)	(22,442)
Interest and financing <sup>(1)</sup>	(5,778)	2,248	(8,026)	(498)	14,195	(14,693)
<b>Total</b>	<b>\$ 62,386</b>	<b>\$ 90,532</b>	<b>\$ (28,146)</b>	<b>\$ 74,381</b>	<b>\$ 48,487</b>	<b>\$ 25,894</b>

(1) Unrealized interest and financing derivative gain (loss) includes the change in fair value of the call options embedded in our senior unsecured notes.

The realized financial derivative gains of \$25.2 million and \$167.1 million for the three and nine months ended September 30, 2015, respectively, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by losses on our foreign exchange contracts.

The unrealized gain of \$37.2 million for the three months ended September 30, 2015 is mainly due to the decline of commodity prices at September 30, 2015 compared to June 30, 2015. The unrealized loss of \$92.7 million for the nine months ended September 30, 2015 is mainly due to the realization or reversal of unrealized gains previously recorded at December 31, 2014 on our commodity contracts.

A summary of the financial derivative contracts in place as at September 30, 2015 and the accounting treatment thereof are disclosed in note 17 to the consolidated financial statements.

## Operating Netback

	Three Months Ended September 30					
	2015			2014		
<i>(\$ per boe except for volume)</i>	Canada	U.S.	Total	Canada	U.S.	Total
Production volume (boe/d)	43,229	38,941	82,169	56,753	37,384	94,137
Operating netback:						
Oil and natural gas revenue	\$ 29.06	\$ 40.72	\$ 34.59	\$ 67.93	\$ 78.28	\$ 72.04
Other income	0.69	—	0.36	—	—	—
Less:						
Royalties	3.88	11.74	7.61	13.45	23.46	17.43
Production and operating expenses	12.31	7.97	10.25	12.70	9.39	11.39
Transportation expenses	2.88	—	1.52	3.92	—	2.36
Operating netback before financial derivatives	\$ 10.68	\$ 21.01	\$ 15.57	\$ 37.86	\$ 45.43	\$ 40.86
Realized financial derivatives gain (loss) <sup>(1)</sup>	—	—	3.33	—	—	(0.47)
Operating netback after financial derivatives	\$ 10.68	\$ 21.01	\$ 18.90	\$ 37.86	\$ 45.43	\$ 40.39

	Nine Months Ended September 30					
	2015			2014		
<i>(\$ per boe except for volume)</i>	Canada	U.S.	Total	Canada	U.S.	Total
Production volume (boe/d)	45,993	39,847	85,840	56,938	16,780	73,718
Operating netback:						
Oil and natural gas revenue	\$ 32.23	\$ 42.73	\$ 37.10	\$ 69.29	\$ 80.99	\$ 71.97
Other income	0.60	—	0.32	—	0.11	0.02
Less:						
Royalties	4.55	12.41	8.20	14.50	24.59	16.80
Production and operating expenses	13.13	7.58	10.55	12.79	9.84	12.12
Transportation expenses	3.37	—	1.81	4.26	—	3.29
Operating netback before financial derivatives	\$ 11.78	\$ 22.74	\$ 16.86	\$ 37.74	\$ 46.67	\$ 39.78
Realized financial derivatives gain (loss) <sup>(1)</sup>	—	—	7.13	—	—	(0.97)
Operating netback after financial derivatives	\$ 11.78	\$ 22.74	\$ 23.99	\$ 37.74	\$ 46.67	\$ 38.81

(1) Financial derivatives reflect realized gains on commodity-related contracts only.

**U.S. RESULTS - IMPACT OF 2014 ACQUISITION AND DISPOSITION ACTIVITY**

In 2015, the U.S. division is comprised of the Eagle Ford assets. The results of operations for the U.S. division in 2014 includes the Bakken assets in North Dakota, which were disposed of on September 24, 2014, and the Eagle Ford assets in Texas, which were acquired on June 11, 2014. This table demonstrates the impact of the 2014 acquisition and disposition activity on the U.S. results.

Three Months Ended September 30						
Daily Production	2015			2014		
	Eagle Ford	North Dakota	Total	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	22,983	—	22,983	22,313	3,183	25,496
NGL	7,522	—	7,522	5,310	145	5,455
Total liquids (bbl/d)	30,505	—	30,505	27,623	3,328	30,951
Natural gas (mcf/d)	50,613	—	50,613	37,578	1,019	38,597
Total production (boe/d)	38,941	—	38,941	33,886	3,498	37,384
<i>(\$ thousands except for % and per boe amounts)</i>						
Revenue	\$ 145,895	\$ —	\$ 145,895	\$ 240,630	\$ 28,604	\$ 269,234
Royalties	42,058	—	42,058	71,788	8,903	80,691
Production and operating expenses	28,544	—	28,544	27,649	4,665	32,314
Operating income	\$ 75,293	\$ —	\$ 75,293	\$ 141,193	\$ 15,036	\$ 156,229
Realized price per boe	\$ 40.72	\$ —	\$ 40.72	\$ 77.19	\$ 88.89	\$ 78.28
Average royalty rate	28.8%	—%	28.8%	29.8%	31.1%	30.0%
Production and operating expenses per boe	\$ 7.97	\$ —	\$ 7.97	\$ 8.87	\$ 14.50	\$ 9.39

Nine Months Ended September 30						
Daily Production	2015			2014		
	Eagle Ford	North Dakota	Total	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	24,305	—	24,305	8,890	3,015	11,905
NGL	7,220	—	7,220	2,096	157	2,253
Total liquids (bbl/d)	31,525	—	31,525	10,986	3,172	14,158
Natural gas (mcf/d)	49,934	—	49,934	14,812	921	15,733
Total production (boe/d)	39,847	—	39,847	13,455	3,326	16,780
<i>(\$ thousands except for % and per boe amounts)</i>						
Revenue	\$ 464,852	\$ —	\$ 464,852	\$ 288,121	\$ 83,327	\$ 371,448
Royalties	134,974	—	134,974	85,557	27,068	112,625
Production and operating expenses	82,465	—	82,465	31,385	13,703	45,088
Operating income	\$ 247,413	\$ —	\$ 247,413	\$ 171,179	\$ 42,556	\$ 213,735
Realized price per boe	\$ 42.73	\$ —	\$ 42.73	\$ 78.33	\$ 91.78	\$ 81.10
Average royalty rate	29.0%	—%	29.0%	29.7%	32.5%	30.4%
Production and operating expenses per boe	\$ 7.58	\$ —	\$ 7.58	\$ 8.54	\$ 15.09	\$ 9.84

## Exploration and Evaluation Expense

Exploration and evaluation expense includes the write-off of undeveloped lands and other assets and will vary period to period depending on the scheduled expiry of leases and our assessment of the development potential of undeveloped land.

Exploration and evaluation expense was \$2.0 million and \$6.5 million for the three and nine months ended September 30, 2015, respectively, compared to \$1.6 million and \$16.1 million for the three and nine months ended September 30, 2014. Exploration and evaluation expense for the three months ended September 30, 2015 was consistent with the same period of 2014. The decrease for the nine months ended September 30, 2015 is primarily related to a decrease in expiration of undeveloped lands.

## Depletion and Depreciation

Three Months Ended September 30						
(\$ thousands except for per boe)	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation <sup>(1)</sup>	\$ 65,525	\$ 95,827	\$ 162,503	\$ 78,573	\$ 92,582	\$ 172,024
Depletion and depreciation per boe	\$ 16.48	\$ 26.75	\$ 21.50	\$ 15.05	\$ 26.92	\$ 19.86

Nine Months Ended September 30						
(\$ thousands except for per boe)	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation <sup>(1)</sup>	\$ 208,354	\$ 287,030	\$ 498,106	\$ 237,029	\$ 121,048	\$ 360,208
Depletion and depreciation per boe	\$ 16.59	\$ 26.39	\$ 21.26	\$ 15.25	\$ 26.42	\$ 17.90

(1) Total includes corporate depreciation.

Depletion and depreciation expense of \$162.5 million and \$498.1 million for the three and nine months ended September 30, 2015, respectively, decreased \$9.5 million and increased \$137.9 million from the same periods in 2014. The decrease of \$9.5 million for three months ended September 30, 2015 compared to the same period in 2014 is mainly due to lower production volumes in Canada. The increase of \$137.9 million in the nine months ended September 30, 2015 compared to the same period in 2014 is mainly due to increased production with the acquisition of the Eagle Ford assets, slightly offset by lower production volumes due to reduced capital spending in Canada combined with the North Dakota disposition. Depletion and depreciation per boe for the three and nine months ended September 30, 2015 of \$21.50/boe and \$21.26/boe, respectively, increased from \$19.86/boe and \$17.90/boe for same periods in 2014, mainly due to the Eagle Ford assets which have higher costs per boe included in the depletable pool.

## Impairment

During the three months ended September 30, 2015, an impairment expense of \$493.2 million was recorded. The impairment charge was recorded on our Eagle Ford assets and is directly attributable to lower commodity prices. The Eagle Ford assets were originally recorded at their fair value at the time of acquisition in June of 2014 when WTI oil price was more than US\$100/bbl. Commodity prices have declined in 2015 and the future market prices have also decreased which has reduced estimated future cash flows for our U.S. operations below the carrying amount of the assets. The impairment resulted in a \$210.3 million reduction to oil and gas properties and a write off of the remaining \$282.9 million of goodwill associated with this acquisition. We have determined that no impairments are required on our Canadian cash-generating units. There were no impairments in the corresponding periods in 2014.

The recoverable amount of each cash-generating unit was determined using the discounted cash flows for proved, probable and, in the case of the U.S. assets, possible reserves as well as the fair value of undeveloped land acreage. In computing the future cash flows of the assets, we made certain assumptions, most significantly about future commodity prices and the discount rate. We assumed a WTI price of approximately US\$55/bbl in 2016, US\$70/bbl in 2017 and US\$75/bbl in 2018. It is possible that commodity prices in those years may be lower than the current estimate which could result in further impairments. A 10% before tax discount rate has been applied to total proved, probable and possible reserves after applying a 50% risk factor to possible reserves to reflect the lower probability of recovery.

## General and Administrative Expenses

(\$ thousands except for % and per boe)	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
General and administrative expenses	\$ 13,976	\$ 16,770	(17)%	\$ 46,588	\$ 42,978	8 %
General and administrative expenses per boe	\$ 1.85	\$ 1.94	(5)%	\$ 1.99	\$ 2.14	(7)%

General and administrative ("G&A") expenses for the three months ended September 30, 2015 were \$14.0 million, a decrease of \$2.8 million from the same period in 2014. G&A expenses have decreased as a result of reductions to staffing levels to coincide with lower activity levels combined with a reduction of all discretionary spending. G&A expenses for the nine months ended September 30, 2015 increased slightly to \$46.6 million from \$43.0 million in 2014. This increase is attributable to the acquisition of the Eagle Ford assets and associated office in Houston.

On a per boe basis, general and administrative expenses have decreased in 2015 from 2014 for both the three and nine month comparative periods with the reduction in discretionary spending and the low incremental G&A costs associated with the Eagle Ford assets.

## Share-based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized 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 \$3.2 million and \$19.4 million for the three and nine months ended September 30, 2015, respectively, compared to \$6.9 million and \$22.9 million for the same periods in 2014. The decrease in share-based compensation expense during 2015 is a result of the lower fair value of share awards granted in 2015 combined with higher forfeitures during the period as compared to 2014.

## Financing Costs

Financing costs include interest on bank loan and long-term debt, non-cash charges related to accretion of asset retirement obligations and the amortization of loan and debt financing costs.

(\$ thousands except for %)	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
Bank loan	\$ 2,361	\$ 9,174	(74)%	\$ 9,785	\$ 16,644	(41)%
Long-term debt	22,680	20,352	11 %	66,053	39,547	67 %
Accretion on asset retirement obligations and other	2,501	1,786	40 %	7,886	5,307	49 %
Financing costs	\$ 27,542	\$ 31,312	(12)%	\$ 83,724	\$ 61,498	36 %

Financing costs decreased by \$3.8 million to \$27.5 million for the three months ended September 30, 2015 compared to \$31.3 million in 2014 mainly due to lower outstanding bank debt levels as a result of the \$606 million of equity financing completed in April 2015. For the nine months ended September 30, 2015, financing costs were \$83.7 million representing an increase of 36% compared to 2014. The increase is mainly a result of the interest on US\$800 million of senior unsecured notes that were issued in conjunction with the Eagle Ford acquisition in June 2014.

## Foreign Exchange

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

(\$ thousands except for % and exchange rates)	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
Unrealized foreign exchange loss	\$ 89,215	\$ 54,937	62 %	\$ 172,182	\$ 40,014	330 %
Realized foreign exchange (gain) loss	(1,696)	2,109	(180)%	(1,583)	3,095	(151)%
Foreign exchange loss	\$ 87,519	\$ 57,046	53 %	\$ 170,599	\$ 43,109	296 %
CAD/USD exchange rates:						
At beginning of period	1.2474	1.0676		1.1601	1.0636	
At end of period	1.3394	1.1208		1.3394	1.1208	

The unrealized foreign exchange loss of \$89.2 million and \$172.2 million for the three and nine months ended September 30, 2015, respectively, was due to our U.S. dollar denominated senior unsecured notes (US\$950 million principal amount) which have increased in value as the Canadian dollar weakened against the U.S. dollar at September 30, 2015 as compared to both June 30, 2015 and December 31, 2014. The realized foreign exchange gains for the three and nine months ended September 30, 2015 was due to day-to-day U.S. dollar denominated transactions as the U.S. dollar strengthened relative to the Canadian dollar over these periods.

## Income Taxes

(\$ thousands)	Three Months Ended September 30			Nine Months Ended September 30		
	2015	2014	Change	2015	2014	Change
Current income tax expense	\$ 178	\$ 52,461	\$ (52,283)	\$ 16,560	\$ 52,461	\$ (35,901)
Deferred income tax (recovery) expense	(91,858)	(11,157)	(80,701)	(145,853)	28,923	(174,776)
Total income tax (recovery) expense	\$ (91,680)	\$ 41,304	\$ (132,984)	\$ (129,293)	\$ 81,384	\$ (210,677)

For the three months ended September 30, 2015, current income tax expense of \$0.2 million decreased by \$52.3 million, as compared to \$52.5 million for the same period in 2014. This decrease primarily relates to the gain on disposition of the North Dakota assets which resulted in current income tax expense of \$52.5 million in 2014. For the nine months ended September 30, 2015, current income tax expense of \$16.6 million decreased by \$35.9 million compared to the same period in 2014. This decrease primarily relates to the gain on disposition of the North Dakota assets which resulted in current income tax expense of \$52.5 million in 2014. This was partially offset by the increase in realized financial derivative gains recorded in 2015 and the increase in previously deferred income being taxed in 2015.

Deferred income tax recovery of \$91.9 million and \$145.9 million for the three months and nine months ended September 30, 2015, respectively, have increased from a recovery of \$11.2 million and an expense of \$28.9 million for the same periods of 2014. These increases are primarily due to the impairment on oil and gas properties in 2015, the increase in unrealized financial derivative losses and the decrease in income deferred for taxation purposes in the future years.

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

## Net Income (Loss)

Net loss for the three months ended September 30, 2015 totaled \$517.9 million compared to net income of \$144.4 million in 2014. The decrease in 2015 was mainly due to an impairment charge of \$493.2 million combined with lower operating netbacks, lower financial derivative gains and higher unrealized foreign exchange losses on U.S. dollar denominated debt partially offset by an income tax recovery compared to the prior period.

Net loss for the nine months ended September 30, 2015 totaled \$720.7 million compared to net income of \$229.0 million in 2014. The decrease in 2015 was due to an impairment charge of \$493.2 million combined with lower operating netbacks, higher unrealized foreign exchange losses on U.S. dollar denominated debt, higher depletion expenses and financing costs, partially offset by higher financial derivative gains and an income tax recovery compared to the prior period.

## Other Comprehensive Income

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. operations not recognized in profit or loss. The foreign currency translation gain of \$217.1 million for the three months ended September 30, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2015 (1.3394 CAD/USD) compared to the exchange rate on June 30, 2015 (1.2474 CAD/USD). The foreign currency translation gain of \$416.4 million for the nine months ended September 30, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at September 30, 2015 (1.3394 CAD/USD) compared to the exchange rate on December 31, 2014 (1.1601 CAD/USD).

## Capital Expenditures

In the first nine months of 2015, our capital program has been significantly curtailed in response to low commodity prices with only minimal capital expenditures occurring and planned in Canada. In the U.S., activity levels have also slowed compared to the last half of 2014.

Capital expenditures for the three and nine months ended September 30, 2015 and 2014 are summarized as follows:

(\$ thousands)	Three Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	\$ 33,484	\$ 93,320	\$ 126,804	\$ 76,621	\$ 153,411	\$ 230,032
Acquisitions, net of divestitures <sup>(1)</sup>	(586)	89	(498)	(388)	(341,520)	(341,908)
Total oil and natural gas capital expenditures	\$ 32,898	\$ 93,409	\$ 126,306	\$ 76,233	\$ (188,109)	\$ (111,876)

(\$ thousands)	Nine Months Ended September 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	\$ 62,446	\$ 317,797	\$ 380,243	\$ 328,994	\$ 222,379	\$ 551,373
Acquisitions, net of divestitures <sup>(1)</sup>	2,234	(12)	2,222	8,349	2,572,470	2,580,819
Total oil and natural gas capital expenditures	\$ 64,680	\$ 317,785	\$ 382,465	\$ 337,343	\$ 2,794,849	\$ 3,132,192

(1) Includes divestiture-related expenses.

During the three months ended September 30, 2015, exploration and development expenditures were \$126.8 million, representing a \$103.2 decrease from the same period in 2014. Exploration and development expenditures in Canada were \$33.5 million for the third quarter, up \$25.8 million from the second quarter of 2015. We experienced a slight recovery in commodity prices at the start of the third quarter as a result we initiated our Canadian drilling program but subsequently curtailed the program as commodity prices declined throughout the quarter. In the third quarter of 2015, we drilled 29.5 net wells (20.3 in Canada and 9.2 in the Eagle Ford) compared to 41.4 net wells (24.0 in Canada, 14.9 in the Eagle Ford and 2.5 in North Dakota) for the same period in 2014.

During the nine months ended September 30, 2015, exploration and development expenditures were \$380.2 million, representing a \$171.1 million decrease from the same period in 2014. In the first nine months of 2015, we drilled 69.8 net wells (31.4 in Canada and 38.4 in the Eagle Ford) compared to 188.8 net wells (163.8 in Canada, 17.8 in the Eagle Ford and 7.2 in North Dakota) for the same period in 2014. Capital expenditures decreased \$266.6 million in Canada and increased \$95.5 million in the U.S. during the nine months ended September 30, 2015 compared to the same period in 2014. Increased spending associated with the Eagle Ford assets accounted for the increase compared to 2014 which included our North Dakota assets, which was disposed of on September 24, 2014. In Canada, the reduction in capital spending of \$266.6 million is mainly attributable to the drop in commodity prices during 2015 compared to the same period in 2014.

## FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends (net of DRIP) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate our ability to generate the cash flow necessary to fund capital investments and dividends.

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

(\$ thousands except for %)	Three Months Ended September 30		Nine Months Ended September 30	
	2015	2014	2015	2014
Cash flow from operating activities	\$ 167,643	\$ 347,102	\$ 543,741	\$ 620,796
Change in non-cash working capital	(39,470)	(24,094)	(52,768)	57,846
Asset retirement expenditures	2,273	3,894	9,879	10,782
Financing costs	(27,542)	(31,312)	(83,724)	(61,498)
Accretion on asset retirement obligations	1,602	1,786	4,768	5,307
Accretion on long-term debt	546	588	1,426	1,044
Funds from operations	\$ 105,052	\$ 297,964	\$ 423,322	\$ 634,277
Dividends declared	\$ 41,550	\$ 119,785	\$ 153,973	\$ 298,509
Reinvested dividends	(24,302)	(30,014)	(57,349)	(69,899)
Cash dividends declared (net of DRIP)	\$ 17,248	\$ 89,771	\$ 96,624	\$ 228,610
Payout ratio	40%	40%	36%	47%
Payout ratio (net of DRIP)	16%	30%	23%	36%

Baytex does not deduct capital expenditures when calculating the payout ratio. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, there can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of \$17.2 million and \$96.6 million for the three and nine months ended September 30, 2015, respectively, were funded by funds from operations of \$105.1 million and \$423.3 million. In response to the prolonged low price commodity environment, Baytex suspended the monthly dividend beginning September 2015.

## 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 2015 capital program capital program by approximately 40% from our initial plans and working with our lending syndicate to relax certain financial covenants on our credit facilities. On April 2, 2015, we closed an equity financing whereby we issued 36,455,000 common shares at a price of \$17.35 per share for aggregate gross proceeds of approximately \$632.5 million. The net proceeds, after issuance costs, of approximately \$606.0 million were utilized to pay down a portion of our credit facilities. We also announced the suspension of our monthly dividend starting in September of 2015.

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; however, there is no certainty that any of the additional sources of capital would be available when required.

The following table summarizes our total monetary debt at September 30, 2015 and December 31, 2014.

(\$ thousands)	September 30, 2015	December 31, 2014
Bank loan <sup>(1)</sup>	\$ 208,195	\$ 666,886
Long-term debt <sup>(1)</sup>	1,581,002	1,418,685
Working capital deficiency <sup>(2)(3)</sup>	160,539	210,409
<b>Total monetary debt</b>	<b>\$ 1,949,736</b>	<b>\$ 2,295,980</b>

(1) Principal amount of instruments.

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

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

At September 30, 2015, total monetary debt was \$1,949.7 million, representing a decrease of \$342.7 million compared to \$2,296.0 million at December 31, 2014. The decrease at September 30, 2015 is primarily attributable to the equity proceeds of US\$606 million which were applied to outstanding bank debt. This was partially offset by the revaluation of our U.S. dollar denominated monetary debt and additional draws on the bank loan to fund the capital expenditure program. The impact of the movement in exchange rates since December 2014 has resulted in an aggregate increase in bank loan and long-term debt of \$190.6 million.

### Bank Loan

Baytex has revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a \$50 million operation loan, a \$950 million syndicated loan and a US\$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities"). On May 25, 2015, Baytex reached an agreement with its lending syndicate to extend the revolving period under the Revolving Facilities to June 4, 2019 (from June 4, 2018).

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). At September 30, 2015, \$208.2 million was drawn on the Revolving Facilities leaving approximately \$1,059.7 million in undrawn credit capacity. Copies of the agreements relating to the Revolving Facilities are accessible on the SEDAR website at [www.sedar.com](http://www.sedar.com) (filed under the categories "Other material contracts" on June 11, 2014, September 9, 2014 and February 24, 2015 and "Material contracts - Credit agreements" on May 27, 2015).

### Long-term Debt

Baytex has four series of senior unsecured notes outstanding that total \$1.58 billion at September 30, 2015. The senior unsecured notes have varying interest rates and maturities as follows:

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

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

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

## Covenants

The following table lists the financial covenants under the Revolving Facilities and the senior unsecured notes, and the compliance therewith as at September 30, 2015.

Covenant Description	Position as at September 30, 2015	
<b>Revolving Facilities</b>	<b>Maximum Ratio</b>	
Senior debt to Capitalization <sup>(1) (2)</sup>	0.65:1.00	0.40:1.00
Senior debt to Bank EBITDA <sup>(1) (5)</sup>	4.75:1.00	2.29:1.00
Total debt to Bank EBITDA <sup>(3) (5)</sup>	4.75:1.00	2.29:1.00
<b>Senior Unsecured Notes</b>	<b>Minimum Ratio</b>	
Fixed charge coverage <sup>(4)</sup>	2:50:1.00	7.02:1.00

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

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

(3) "Total debt" is defined as the sum of the principal amount of our bank loan, principal amount of long-term debt, and certain other liabilities identified in the credit agreement.

(4) Fixed charge coverage is computed as the ratio of financing costs to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended September 30, 2015 was \$787.5 million.

(5) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income taxes, certain specific unrealized and non-cash transactions (including depletion, depreciation, amortization, impairment, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange, and share-based compensation), and acquisition and disposition activity and is calculated based on a trailing twelve month basis.

On February 20, 2015, we reached an agreement with our lending syndicate to amend the financial covenants contained in the Revolving Facilities as follows: a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 0.55:1.00 thereafter; b) the maximum Senior Debt to Bank EBITDA ratio will be 4.75:1.00 for the period December 31, 2014 up to and including June 30, 2016, 4.50:1.00 for the period July 1, 2016 up to and including December 31, 2016, and 3.50:1.00 thereafter; and c) the maximum Total Debt to Bank EBITDA will be 4.75:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 4.00:1.00 thereafter. If we exceed or breach any of the covenants under the Revolving Facilities or our senior unsecured notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from paying dividends to our shareholders.

## 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 we 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 us 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, 2015 and the accounting treatment thereof is disclosed in note 17 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 October 30, 2015, we had 210,264,243 common shares and no preferred shares issued and outstanding. During the nine months ended September 30, 2015, shares were issued through the equity financing, the DRIP and our share-based compensation programs.

## 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, 2015 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	\$ 260,141	\$ 260,141	\$ —	\$ —	\$ —
Bank loan <sup>(1) (2)</sup>	208,195	—	—	208,195	—
Long-term debt <sup>(2)</sup>	1,581,002	—	—	8,572	1,572,430
Operating leases	52,112	8,006	16,333	15,830	11,943
Processing agreements	56,325	10,230	12,369	9,043	24,683
Transportation agreements	75,379	13,427	23,369	22,618	15,965
<b>Total</b>	<b>\$ 2,233,154</b>	<b>\$ 291,804</b>	<b>\$ 52,071</b>	<b>\$ 264,258</b>	<b>\$ 1,625,021</b>

(1) The bank loan is a covenant-based loan 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 re-paid on such date.

(2) Principal amount of instruments.

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

## OFF BALANCE SHEET TRANSACTIONS

Baytex does not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2015, nor are any such arrangements outstanding as of the date of this MD&A.

## QUARTERLY FINANCIAL INFORMATION

(\$ thousands, except per common share amounts)	2015			2014			2013	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Gross revenues	268,625	345,432	285,615	472,394	634,415	476,404	385,809	330,712
Net income (loss)	(517,856)	(26,955)	(175,916)	(361,816)	144,369	36,799	47,841	31,173
Per common share - basic	(2.49)	(0.13)	(1.04)	(2.16)	0.87	0.27	0.38	0.26
Per common share - diluted	(2.49)	(0.13)	(1.04)	(2.16)	0.86	0.27	0.38	0.25

## FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our annual average production rate for 2015; our capital expenditures for 2015; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the proposed reassessment of our tax filings by the CRA to deny non-capital loss deductions for taxation years 2011 through 2013, including our intention to file tax returns for subsequent taxation years in a manner consistent with previous filings, our view of our tax filing position and our intention to defend the proposed reassessments if issued by the CRA; our ability to sustain our operations and planned capital expenditures utilizing internally generated funds from operations and our existing undrawn credit facilities; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; and the existence, operation and strategy of our risk management program, including our intent of partially mitigating some of the volatility in our funds from operations through a series of derivative contracts. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

*Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.*

*These forward-looking statements are based on certain key assumptions regarding, among other things: our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.*

*Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices; substantial or extended declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the capital markets that may restrict the availability of or increase the cost of capital or of borrowing; refinancing risk for existing debt and the risk of failing to comply with covenants in existing debt agreements; risks associated with properties operated by third parties, specifically with respect to a substantially majority of our Eagle Ford assets; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; 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 hazards associated with acquiring, developing and exploring for oil and natural gas; business risks; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond 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, 2014, 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.*