BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2015 and 2014
Dated March 2, 2016

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the year ended December 31, 2015. This information is provided as of March 2, 2016. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The year to date results have been compared with the corresponding period in 2014. This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2015 and 2014, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2015. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

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

NON-GAAP FINANCIAL MEASURES

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

Funds from Operations

The Company considers funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and future 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).

	Years Ended December 31	
($ thousands)	**2015**	2014
Cash flow from operating activities	**$ 549,420**	$ 897,152
Change in non-cash working capital	**(43,891)**	(31,890)
Asset retirement expenditures	**10,888**	14,528
Funds from operations	**$ 516,417**	$ 879,790

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 December 31, 2015 and 2014.

($ thousands)	**December 31, 2015**	December 31, 2014
Bank loan[1]	**$ 256,749**	$ 666,886
Long-term notes[1]	**1,623,658**	1,418,685
Working capital deficiency[2][3]	**169,498**	210,409
Net debt	**$ 2,049,905**	$ 2,295,980

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

Operating Netback

We define operating netback as oil and natural gas revenue, less royalties, operating expenses and transportation expenses. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in characterizing 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).

	Years Ended December 31	
($ thousands)	**2015**	2014
Net income (loss)	**$ (1,133,651)**	$ (132,807)
Plus:		
Financing costs	**111,660**	90,033
Income tax expense (recovery)	**(344,146)**	134,391
Depletion and depreciation	**661,858**	536,569
EBITDA attributable to acquired assets	**—**	254,087
Other non-cash items[1]	**1,333,007**	414,898
Bank EBITDA	**$ 628,728**	$ 1,297,171

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

YEAR END HIGHLIGHTS

2015 was a challenging year as world oil prices declined significantly from 2014 and we continually adjusted our business in response. Throughout the year, the Company took steps to protect its liquidity in order to withstand the low commodity price environment. Despite these changes, the Company was able to achieve production of 84,648 boe/d, advance the multi-zone potential of its Eagle Ford asset and achieve cost reductions in all aspects of the business.

Production for the year ended December 31, 2015 increased 8% to 84,648 boe/d mainly due to growth from the Eagle Ford assets which was partially offset by declines in Canada. U.S. production averaged 39,957 boe/d in 2015 and was 80%, or 17,819 boe/d, higher than 2014. Production from the Company's Eagle Ford assets was included for the full year in 2015 and has increased more than 11,000 boe/d since the acquisition in June of 2014. This was partially offset by the North Dakota disposition which closed on September 24, 2014. Canadian production averaged 44,691 boe/d in 2015, a decrease of 21%, from 56,257 boe/d in 2014. Reduced capital spending, property dispositions and shut-in production contributed to reduced production levels on our Canadian assets in 2015.

Funds from operations for the year ended December 31, 2015 was $516.4 million, compared to $879.8 million in 2014. The decrease in FFO was directly attributable to lower commodity prices. The Company's realized sales price of $35.40/boe decreased 47% from the prior year driven by a 48% decrease in the price of West Texas Intermediate light oil ("WTI") for the year. WTI prices averaged US$48.79/bbl in 2015 compared to US$92.97/bbl in 2014.

In response to the lower commodity prices, we continued to reduce our capital program throughout 2015 investing a total of $521.0 million for the year. Capital spending was focused on our Eagle Ford assets with 86% of total capital being spent in the U.S. Spending in the U.S. totaled $449.8 million in 2015 compared to $371.8 million in 2014 where we drilled 50.2 net wells in 2015 compared to 33.2 net wells in 2014. In the Eagle Ford, we were able to further advance the multi-zone potential of the acreage which resulted in additional reserves and enhanced economics in this play. Activity in Canada was significantly reduced in 2015 as we drilled 31.4 net wells and spent $71.3 million compared to 175.1 net wells and $394.2 million in 2014.

With the low commodity environment, we took several steps to protect our liquidity. On April 2, 2015, we completed an equity financing, issuing 36,455,000 common shares at a price of $17.35 per share for net proceeds of $606.0 million. In September, we made the difficult decision to suspend our dividend and reduce our capital program. We have also worked with our bank lending syndicate throughout 2015. We received covenant relief in early 2015, extended the maturities of our credit facilities by one year in June and negotiated further covenant relief in December. We also chose to voluntarily reduce our Canadian credit facilities by $200 million as the carrying costs were increasing and we could not see ourselves utilizing the full amount of the facility in the current environment. At December 31, 2015, the Company was in compliance with all of its financial covenants and $256.7 million was drawn on the facilities leaving approximately $820.0 million in undrawn credit capacity.

During the year, we recorded total impairment charges of $1.0 billion ($992.9 million related to Eagle Ford assets and $45.7 million to Canadian assets). The impairment charges are directly attributable to the decline in commodity prices. The Eagle Ford 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 since the date of acquisition on June 11, 2014.

Production

	Years Ended December 31					
	2015			2014		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**34,974**	**—**	**34,974**	45,022	—	45,022
Light oil and condensate	**1,828**	**24,059**	**25,887**	2,621	15,060	17,681
NGL	**1,070**	**7,422**	**8,492**	1,441	3,378	4,819
Total liquids (bbl/d)	**37,872**	**31,481**	**69,353**	49,084	18,438	67,522
Natural gas (mcf/d)	**40,911**	**50,855**	**91,766**	43,037	22,197	65,234
Total production (boe/d)	**44,691**	**39,957**	**84,648**	56,257	22,138	78,395
Production Mix						
Heavy oil	**79%**	**—%**	**41%**	79%	—%	56%
Light oil and condensate	**4%**	**61%**	**31%**	5%	68%	24%
NGL	**2%**	**19%**	**10%**	3%	15%	6%
Natural gas	**15%**	**20%**	**18%**	13%	17%	14%

Annual average production for the year ended December 31, 2015 was 84,648 boe/d, representing an 8% increase, or 6,253 boe/d, compared to 2014. The increase in 2015 is primarily due to production from the Eagle Ford acquisition. Canadian production of 44,691 boe/d decreased 21%, or 11,566 boe/d, from 2014. The Canadian decrease is attributable to natural declines associated with reduced capital spending along with non-core dispositions and uneconomic production we have shut-in which total approximately 2,900 boe/d for the year. At December 31, 2015, we had approximately 2,400 boe/d of uneconomic production shut-in. U.S. production for the year ended December 31, 2015 was 39,957 boe/d, an increase of 80% over the prior year as production from our Eagle Ford assets contributed for the full-year 2015 compared to 2014 where they were only included since the date of acquisition on June 11, 2014. This was offset by the divestiture of the North Dakota production which produced 2,483 boe/d for 2014. The Eagle Ford 2014 production for the three months ended December 31, 2014 was 38,035 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 the year ended December 31, 2015, the WTI oil prompt averaged US$48.79/bbl, a 48% decrease from the average WTI price of US$92.97/bbl in 2014. The low prices experienced during year ended 2015, as compared to 2014, were due to a persistent global over supply of oil due in part to the decision of the Organization of Petroleum Exporting Countries (OPEC) to step away from its traditional swing producer role.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 29% for the year ended December 31, 2015, as compared to 21% in 2014. While on a percentage basis the WCS differential widened, the differential narrowed in nominal terms to average US$13.52/bbl for the year ended December 31, 2015 as compared to US$19.40/bbl in 2014. The improvement in the nominal differential was due to increased pipeline capacity from Canada to the U.S. Gulf Coast, which allows WCS pricing to achieve pipeline equivalency with the large waterborne Gulf Coast refinery market.

Natural Gas

For the year ended December 31, 2015, the AECO natural gas prices averaged $2.74/mcf, a 38% decrease compared to $4.42/mcf in 2014. For the year ended December 31, 2015, the NYMEX natural gas price averaged US$2.66/mmbtu, a 40% decrease compared to US$4.41/mmbtu in 2014. The decrease in natural gas prices on both indices during 2015 was driven by historically high production levels which exceeded current demand.

The following table compares selected benchmark prices and our average realized selling prices for the years ended December 31, 2015 and 2014.

	Years Ended December 31		
	2015	2014	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**48.79**	92.97	(48)%
WCS heavy oil (US$/bbl)(2)	**35.26**	73.58	(52)%
Heavy oil differential(3)	**29%**	21%	
LLS oil (US$/bbl)(4)	**51.50**	96.76	(47)%
CAD/USD average exchange rate	**1.2811**	1.1050	16 %
Edmonton par oil ($/bbl)	**57.20**	95.28	(40)%
AECO natural gas price ($/mcf)(5)	**2.74**	4.42	(38)%
NYMEX natural gas price (US$/mmbtu)(6)	**2.66**	4.41	(40)%

(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.

	Years Ended December 31					
	2015			2014		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Sales Prices(1)						
Canadian heavy oil ($/bbl)(1)	**$ 32.23**	**$ —**	**$ 32.23**	$ 69.64	$ —	$ 69.64
Light oil and condensate ($/bbl)	**52.52**	**55.99**	**55.75**	89.88	91.63	91.37
NGL ($/bbl)	**20.80**	**16.35**	**16.91**	45.49	30.93	35.28
Natural gas ($/mcf)	**2.59**	**3.47**	**3.08**	4.49	4.62	4.53
Weighted average ($/boe)(2)	**$ 30.24**	**$ 41.16**	**$ 35.40**	$ 64.52	$ 71.69	$ 66.54

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.
(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

Average Realized Sales Prices

Our realized heavy oil price for the year ended December 31, 2015 was $32.23/bbl, or 71% of WCS, compared to $69.64/bbl, or 86% of WCS in 2014. The Company's decrease in realized heavy oil price of 54% for the year ended December 31, 2015 compared to 2014 corresponds with the 52% change in WCS heavy oil price over the same period. 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 2015 compared to 2014.

During the year ended December 31, 2015, our Canadian average sales price for light oil and condensate was $52.52/bbl, down 42% from $89.88/bbl in 2014. This corresponds with the 40% decrease in the benchmark Edmonton Par prices over the same period. U.S. light oil and condensate pricing for the year ended December 31, 2015 was $55.99/bbl, down 39% from $91.63/bbl in 2014, which is consistent with a 38% decrease in the LLS benchmark (as expressed in Canadian dollars).

Our realized natural gas price for the year ended December 31, 2015 was $3.08/mcf, down from $4.53/mcf in 2014. This is largely in line with the decreases in the AECO and NYMEX benchmarks during these periods.

Gross Revenues

	Years Ended December 31					
	2015			2014		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 411,386**	**$ —**	**$ 411,386**	$ 1,144,360	$ —	$ 1,144,360
Light oil and condensate	**35,044**	**491,700**	**526,744**	85,986	503,701	589,687
NGL	**8,121**	**44,286**	**52,407**	23,924	38,136	62,060
Total liquids revenue	**454,551**	**535,986**	**990,537**	1,254,270	541,837	1,796,107
Natural gas revenue	**38,723**	**64,334**	**103,057**	70,514	37,418	107,932
Total oil and natural gas revenue	**493,274**	**600,320**	**1,093,594**	1,324,784	579,255	1,904,039
Other income(1)	**—**	**—**	**8,448**	—	—	6,863
Heavy oil blending revenue	**27,830**	**—**	**27,830**	58,120	—	58,120
Total petroleum and natural gas revenues	**$ 521,104**	**$ 600,320**	**$ 1,129,872**	$ 1,382,904	$ 579,255	$ 1,969,022

(1) Total includes corporate other income

Total petroleum and natural gas revenues for the year ended December 31, 2015 of $1,129.9 million decreased $839.2 million from the prior year. This decrease can be attributed to the drop in commodity prices which decreased petroleum and natural gas revenues by $962 million during 2015 which was partially offset by higher production volumes which increased petroleum and natural gas revenues by $152 million. In Canada, petroleum and natural gas revenues for the year ended December 31, 2015 totaled $521.1 million, a decrease of $861.8 million compared to 2014. The lower petroleum and natural gas revenues in 2015 were due to lower production volumes and lower realized prices on all products. Petroleum and natural gas revenues of $600.3 million in the U.S. increased $21.1 million from the prior year with increased production from the acquisition of the Eagle Ford assets which was offset by the decrease in realized prices on all products.

Heavy oil blending revenue of $27.8 million for the year ended December 31, 2015 decreased $30.3 million compared to 2014. 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 purchases and sales are recorded as heavy oil blending revenue and expense, respectively. Heavy oil blending revenue decreased as the price of diluent decreased in the year and the Company sold less diluent with the decrease in heavy oil production within Canada.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2015 and 2014.

	Years Ended December 31					
	2015			2014		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 67,323**	**$ 174,102**	**$ 241,425**	$ 265,066	$ 174,059	$ 439,125
Average royalty rate(1)	**13.6%**	**29.0%**	**22.1%**	20.0%	30.0%	23.1%
Royalty rate per boe	**$ 4.13**	**$ 11.94**	**$ 7.81**	$ 12.91	$ 21.54	$ 15.35

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

Total royalties for the year ended December 31, 2015 of $241.4 million decreased 45%, or $197.7 million from 2014, mainly due to the decline in gross revenues. Canadian royalties decreased to 13.6% of revenue for the year ended December 31, 2015, compared to 20.0% of revenue in 2014. Canadian crown royalty rates are partially based on price and with the lower commodity prices during 2015 the Company experienced lower crown royalty rates compared to 2014. U.S. royalties of $174.1 million for year ended December 31, 2015 is consistent with 2014 as the slight increase in revenues during the year was offset by a slightly lower royalty rate. Royalty rates in the U.S. for 2015 have decreased to 29.0% compared to 30.0% in the prior year due to the disposition of the North Dakota assets that had a higher royalty rate than the Eagle Ford assets.

Operating Expenses

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expenses	**$ 210,945**	**$ 109,242**	**$ 320,187**	$ 272,515	$ 81,334	$ 353,849
Operating expenses per boe	**$ 12.93**	**$ 7.49**	**$ 10.36**	$ 13.27	$ 10.07	$ 12.37

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

Operating expenses for the year ended December 31, 2015 of $320.2 million decreased $33.7 million compared to 2014. On a per boe basis, operating expenses for the year ended December 31, 2015 decreased $2.01/boe to $10.36/boe, compared to $12.37/boe in 2014. Operating expenses per boe have decreased 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 operating expenses of $210.9 million for the year ended December 31, 2015 decreased $61.6 million compared to 2014. The decrease is a result of lower production volumes and realized cost savings across all of our operations. With realized cost savings from service providers, lower fuel costs and reduced labour costs, our Canadian operating expenses per boe for the year ended December 31, 2015 decreased $0.34/boe to $12.93/boe, compared to $13.27/boe in 2014. Despite significant reductions in our operating costs, the savings per boe were somewhat offset by fixed costs on lower production volumes.

U.S. operating expenses of $109.2 million for the year ended December 31, 2015, increased $27.9 million compared to 2014 due to the increase in production. On a per boe basis, costs decreased $2.58/boe to $7.49/boe for the year ended December 31, 2015. The costs per boe have decreased with the acquisition of the Eagle Ford assets which have a lower operating cost than the North Dakota properties. Costs in the Eagle Ford have also decreased since the acquisition through lower service costs and from fixed costs being spread over a growing production base.

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 years ended December 31, 2015 and 2014.

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expenses	**53,127**	**—**	**53,127**	83,766	—	83,766
Transportation expense per boe	**$ 3.26**	**$ —**	**$ 1.72**	$ 4.08	$ —	$ 2.93

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

Transportation expenses for the year ended December 31, 2015 totaled $53.1 million, a decrease of 36%, or $30.6 million, compared to 2014. 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.

Blending Expenses

Blending expenses for the year ended December 31, 2015 of $27.8 million have decreased $30.3 million or 52%, compared to 2014. 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. 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.

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 years ended December 31, 2015 and 2014.

	Years Ended December 31		
($ thousands)	**2015**	2014	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 235,393**	$ 46,844	$ 188,549
Natural gas	**8,549**	(974)	9,523
Foreign currency	**(46,397)**	(10,416)	(35,981)
Interest	**—**	(8,130)	8,130
Total	**$ 197,545**	$ 27,324	$ 170,221
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (70,354)**	$ 186,115	$ (256,469)
Natural gas	**968**	5,802	(4,834)
Foreign currency	**15,068**	(8,737)	23,805
Interest and financing	**(498)**	2,020	(2,518)
Total	**$ (54,816)**	$ 185,200	$ (240,016)
Total financial derivatives gain (loss)			
Crude oil	**$ 165,039**	$ 232,959	$ (67,920)
Natural gas	**9,517**	4,828	4,689
Foreign currency	**(31,329)**	(19,153)	(12,176)
Interest and financing[(1)]	**(498)**	(6,110)	5,612
Total	**$ 142,729**	$ 212,524	$ (69,795)

(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 gain of $197.5 million for the year ended December 31, 2015, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by $15.1 million of losses on our foreign exchange contracts.

The unrealized loss of $54.8 million for the year ended December 31, 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 December 31, 2015 and the accounting treatment thereof are disclosed in note 19 to the consolidated financial statements.

Operating Netback

	Years Ended December 31					
	2015			2014		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**44,691**	**39,957**	**84,648**	56,257	22,138	78,395
Operating netback:						
Oil and natural gas revenues	**$ 30.24**	**$ 41.16**	**$ 35.40**	$ 64.52	$ 71.69	$ 66.54
Other income	**—**	**—**	**0.27**	—	—	0.24
Less:						
Royalties	**4.13**	**11.94**	**7.81**	12.91	21.54	15.35
Operating expenses	**12.93**	**7.49**	**10.36**	13.27	10.07	12.37
Transportation expenses	**3.26**	**—**	**1.72**	4.08	—	2.93
Operating netback	**$ 9.92**	**$ 21.73**	**$ 15.78**	$ 34.57	$ 40.13	$ 36.13
Financial derivatives gain	**—**	**—**	**6.39**	—	—	1.24
Operating netback after financial derivatives	**$ 9.92**	**$ 21.73**	**$ 22.17**	$ 34.57	$ 40.13	$ 37.37

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 included 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.

	Years Ended December 31					
	2015			2014		
Daily Production	**Eagle Ford**	**North Dakota**	**Total**	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	**24,059**	**—**	**24,059**	12,805	2,255	15,060
NGL	**7,422**	**—**	**7,422**	3,264	114	3,378
Total liquids (bbl/d)	**31,481**	**—**	**31,481**	16,069	2,369	18,438
Natural gas (mcf/d)	**50,855**	**—**	**50,855**	21,511	687	22,198
Total production (boe/d)	**39,957**	**—**	**39,957**	19,654	2,483	22,138
($ thousands except for % and per boe amounts)						
Revenue	**$ 600,320**	**$ —**	**$ 600,320**	$ 495,981	$ 83,274	$ 579,255
Royalties	**174,102**	**—**	**174,102**	146,954	27,105	174,059
Operating expenses	**109,242**	**—**	**109,242**	67,508	13,826	81,334
Operating netback	**$ 316,976**	**$ —**	**$ 316,976**	$ 281,519	$ 42,343	$ 323,862
Realized price per boe	**$ 41.16**	**$ —**	**$ 41.16**	$ 69.14	$ 91.88	$ 71.69
Average royalty rate	**29.0%**	**—%**	**29.0%**	29.6%	32.5%	30.0%
Operating expenses per boe	**$ 7.49**	**$ —**	**$ 7.49**	$ 9.41	$ 15.25	$ 10.07

Exploration and Evaluation Expense

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

Exploration and evaluation expense decreased to $8.8 million for the year ended December 31, 2015 from $17.7 million in 2014. The decrease for the year ended December 31, 2015 is due to lower expiries of undeveloped land in 2015.

Depletion and Depreciation

	Years Ended December 31					
	2015			2014		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[1]	**$ 279,744**	**$ 377,847**	**$ 661,858**	$ 328,902	$ 204,461	$ 536,569
Depletion and depreciation per boe	**$ 17.15**	**$ 25.91**	**$ 21.42**	$ 16.02	$ 25.30	$ 18.75

(1) Total includes corporate depreciation.

Depletion and depreciation expense totaled $661.9 million for the year ended December 31, 2015, as compared to $536.6 million in 2014. The increase of $115.9 million in the year ended December 31, 2015 compared to 2014 is due to increased production and a higher depletion rate.The depletion rate per boe for the year ended December 31, 2015 increased to $21.42/boe from $18.75/boe in 2014, as the Eagle Ford assets were included in the depletable base for all of 2015 and they have a higher cost base and depletion rate than assets in Canada.

Impairment

Impairment expense totaled $1,038.6 million for the year ended December 31, 2015, as compared to $449.6 million in 2014. An impairment charge of $992.9 million 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 the estimated future cash flows for our U.S. cash-generating unit below the carrying amount of the assets. The impairment included the remaining $282.9 million of goodwill associated with this acquisition along with $710.0 million related to oil and gas properties.

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$41.44/bbl in 2016, US$60.00/bbl in 2017 and US$70.00/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 discount rate of 10% before tax has been applied to the cash flows.

During the year it was determined that access to explore and develop certain lands in our Lloydminster cash-generating unit was going to be limited, as a result we recorded an impairment charge of $45.7 million on certain Canadian assets that were part of our Lloydminster cash-generating unit. The lands were subsequently disposed of in November 2015.

General and Administrative Expenses

	Years Ended December 31		
($ thousands except for per boe)	**2015**	2014	Change
General and administrative expenses	**$ 59,406**	$ 59,957	(1)%
General and administrative expenses per boe	**$ 1.92**	$ 2.10	(9)%

General and administrative ("G&A") expenses for the year ended December 31, 2015 decreased slightly to $59.4 million from $60.0 million, a decrease of $0.6 million from 2014. On a per boe basis, G&A expenses decreased 9% in 2015 from 2014. The decrease is attributable to reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending. This was offset by the acquisition of the Eagle Ford assets and associated office in Houston which contributed $11.8 million to G&A in 2015.

Acquisition-Related Costs

During the year ended December 31, 2014, we incurred acquisition-related costs for the Aurora acquisition of $38.6 million. These costs included legal, regulatory and advisory fees along with foreign currency hedge premiums. No acquisition-related costs were incurred for the year ended December 31, 2015.

Gain (Loss) on Divestiture of Oil and Gas Properties

For the year ended December 31, 2015, the Company recorded losses on non-core dispositions of oil and gas properties of $1.5 million before tax. In 2014, the Company recorded gains of $50.2 million before tax on dispositions related to the disposition of the North Dakota assets and other non-core dispositions in Canada.

Share-Based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan decreased to $15.3 million for the year ended December 31, 2015 from $27.5 million in 2014. The decrease in share-based compensation expense during 2015 is a result of the lower fair value of share awards granted combined with higher forfeitures related to a reduction in staffing levels during 2015 as compared to 2014.

Financing Costs

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

	Years Ended December 31		
($ thousands except for %)	**2015**	2014	Change
Interest on bank loan	**$ 20,566**	$ 21,854	(6)%
Interest on long-term notes	**82,838**	59,231	40 %
Non-cash financing costs	**1,994**	1,697	18 %
Accretion on asset retirement obligations	**6,262**	7,251	(14)%
Financing costs	**$ 111,660**	$ 90,033	24 %

Financing costs increased by $21.6 million to $111.7 million for the year ended December 31, 2015, compared to $90.0 million in 2014. Interest on long-term notes increased with increased debt levels as the Company issued US$800 million of senior unsecured notes in conjunction with the Eagle Ford acquisition in June 2014. In addition, a large portion of the Company's borrowings are in U.S. dollars which resulted in higher interest expense as the Canadian dollar weakened throughout 2015.

Foreign Exchange

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

	Years Ended December 31		
($ thousands except for exchange rates)	**2015**	2014	Change
Unrealized foreign exchange loss	**$ 213,999**	$ 75,011	185 %
Realized foreign exchange (gain) loss	**(3,286)**	370	(988)%
Foreign exchange loss	**$ 210,713**	$ 75,381	180 %
CAD/USD exchange rates:			
At beginning of period	**1.1601**	1.0636	
At end of period	**1.3840**	1.1601	

The Company recorded unrealized foreign exchange loss of $214.0 million for the year ended December 31, 2015, as the liability related to its U.S. dollar denominated senior unsecured notes increased $214.0 million due to the Canadian dollar weakening against the U.S. dollar at December 31, 2015 as compared to December 31, 2014. The realized foreign exchange gain for the year ended December 31, 2015 were due to day-to-day U.S. dollar denominated transactions.

Income Taxes

	Years Ended December 31		
($ thousands)	**2015**	2014	Change
Current income tax expense	**$ 8,907**	$ 53,875	$ (44,968)
Deferred income tax (recovery) expense	**(353,053)**	80,516	(433,569)
Total income tax (recovery) expense	**$ (344,146)**	$ 134,391	$ (478,537)

For the year ended December 31, 2015, current income tax expense of $8.9 million decreased by $45.0 million, as compared to $53.9 million for 2014. The decrease primarily relates to a reduction in U.S. current income taxes associated with the 2014 disposition of North Dakota assets (which contributed $52.5 million to current income taxes that year). This was offset by an increase in Canadian income taxes associated with the increased realized financial derivative gains recorded and taxed in 2015 along with Canadian operating income recorded in 2014 that was deferred to 2015 taxation.

The deferred income tax recovery of $353.1 million for the year ended December 31, 2015 increased $433.6 million from an expense of $80.5 million for 2014. The increase is primarily due to the larger net loss in the period from impairment charges and the decrease in U.S. operating income.

Tax Pools

The Company has Canadian and US tax pools, which are available to reduce future taxable income. Our cash income tax liability is dependent upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and currently enacted tax laws in Canada and the United States, Baytex expects to receive a refund of approximately $7 million of Canadian cash income taxes during 2016.

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 is entitled to deduct the non-capital losses, that its tax filings to-date are correct, and has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a reply to Baytex's letter. The Company expects to continue to defend the position as filed.

The income tax pools detailed below are deductible at various rates as prescribed by law:

($ thousands)	**December 31, 2015**	December 31, 2014
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 231,168**	$ 237,734
Canadian development expenditures	**347,014**	490,721
Canadian exploration expenditures	**94**	611
Undepreciated capital costs	**339,635**	428,830
Non-capital losses	**63,064**	132,522
Financing costs and other	**84,734**	76,780
Total Canadian tax pools	**$ 1,065,709**	$ 1,367,198
U.S. Tax Pools		
Depletion	**$ 383,551**	$ 354,149
Intangible drilling costs	**439,380**	311,586
Tangibles	**149,971**	209,655
Non-capital losses	**1,046,951**	553,172
Other	**65,669**	79,212
Total U.S. tax pools	**$ 2,085,522**	$ 1,507,774

Net Income (Loss) and Funds From Operations

The net loss for 2015 totaled $1,133.7 million ($5.72 per basic and diluted share) compared to net loss of $132.8 million ($0.89 per basic and diluted share) in 2014. The funds from operations for 2015 totaled $516.4 million ($2.61 per basic and diluted share) as compared to $879.8 million ($5.91 per basic and diluted share) in 2014. The components of the change in net income (loss) and funds from operations from 2014 are detailed in the following table:

		Net income (loss)	Funds from operations
Year ended December 31, 2014	$	(132,807) $	879,790
Decrease in			
Operating netback		(546,859)	(546,859)
Current income tax expense		44,968	44,968
Unrealized financial derivatives gain		(240,016)	—
Increase in			
Realized financial derivatives gain		170,221	170,221
Depletion and depreciation		(125,289)	—
Impairment		(588,964)	—
Unrealized foreign exchange loss		(138,988)	—
Deferred income tax (recovery)		433,569	—
Other(1)(2)		(9,486)	(31,703)
Year ended December 31, 2015	**$**	**(1,133,651) $**	**516,417**

(1) For net income (loss), other includes exploration and evaluation expense, general and administrative expense, acquisition-related costs, share-based compensation, financing costs, realized foreign exchange loss and gain on disposition.
(2) For funds from operations, other includes general and administrative expenses, acquisition-related expenses, interest on bank loan and long-term notes and realized foreign exchange loss.

Dividends

In 2015, we declared monthly dividends of $0.10 per share for January to August totaling $0.80 per share ($2.64 per share - 2014). The Company paid $96.6 million in cash dividends for the year ended December 31, 2015, and $57.3 million of dividends declared was settled by issuing 4,707,914 shares under the Company's dividend reinvestment plan. In response to the prolonged low price commodity environment, Baytex suspended the monthly dividend beginning 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 $505.8 million foreign currency translation gain for the year ended December 31, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at December 31, 2015 compared to the exchange rate on December 31, 2014.

Capital Expenditures

Capital expenditures for the years ended December 31, 2015 and 2014 are summarized as follows:

	Years Ended December 31					
	2015			2014		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 4,704**	**$ 276**	**$ 4,980**	$ 7,250	$ 1,339	$ 8,589
Seismic	**300**	**—**	**300**	1,894	30	1,924
Drilling, completion and equipping	**45,937**	**420,559**	**466,496**	296,284	366,931	663,215
Facilities	**20,309**	**28,954**	**49,263**	88,800	3,543	92,343
Total exploration and development	**$ 71,250**	**$ 449,789**	**$ 521,039**	$ 394,228	$ 371,843	$ 766,071
Total acquisitions, net of divestitures	**1,641**	**7**	**1,648**	(33,863)	2,579,019	2,545,156
Total oil and natural gas expenditures	**$ 72,891**	**$ 449,796**	**$ 522,687**	$ 360,365	$ 2,950,862	$ 3,311,227

In response to the lower commodity prices, we reduced our capital program throughout the year with 2015 exploration and development expenditures of $521.0 million compared to $766.1 million in 2014. Capital spending was focused on our Eagle Ford assets with 86% of total capital being spent in the U.S. Spending in the U.S. totaled $449.8 million in 2015 compared to $371.8 million in 2014 and we drilled 50.2 net wells in 2015 compared to 33.2 net wells in 2014. 2014 exploration and development expenditures included Eagle Ford development from the acquisition date in June of 2014 and included $56.2 million of expenditures on the North Dakota assets. In 2015, we worked with our partner in the Eagle Ford to achieve significant cost savings. Drilling, completions and equipping costs per well have decreased from approximately US$8.5 million in 2014 to approximately US$6.2 million in 2015. The weakening of the Canadian dollar offset some of the cost savings achieved.

Activity in Canada was significantly reduced in 2015 as we drilled 31.4 net wells and spent $71.3 million compared to 175.1 net wells and $394.2 million in 2014. Despite achieving cost reductions of approximately 20% in Canada, the commodity prices did not support drilling in Peace River or Lloydminster in the second half of 2015 which resulted in significantly less expenditures for the year.

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 by approximately 40% from our initial plans and working with our lending syndicate to relax certain financial covenants related to our credit facilities on February 19, 2015 and again on December 8, 2015. On April 2, 2015, we closed an equity financing and 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.

At December 31, 2015, net debt was $2,049.9 million, as compared to $2,296.0 million at December 31, 2014. The decrease at December 31, 2015 is primarily attributable to the equity proceeds of $606.0 million being applied to outstanding bank debt. This was partially offset by the increase in our U.S. dollar denominated bank loan and long-term notes of $240.4 million due to the weakening Canadian dollar and a $114.4 million increase in credit facilities as dividend payments and capital expenditures exceeded funds from operations.

Bank Loan

Baytex has revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a $50 million operation loan, a $750 million syndicated loan and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants 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). Copies of the agreements relating to the Revolving Facilities are accessible on the SEDAR website at 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 and January 7, 2016).

The weighted average interest rate on the credit facilities for the year ended December 31, 2015 was 3.32% (year ended December 31, 2014 - 3.25%).

Long-Term Notes

Baytex has five series of senior unsecured notes outstanding that total $1.62 billion as at December 31, 2015. The senior unsecured notes do not contain any significant financial maintenance covenants. The notes contain a minimum fixed charge coverage ratio covenant as a debt incurrence covenant which, if not met, limits the Company from taking on new borrowings beyond existing senior unsecured notes and credit facilities.

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

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

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

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

Covenants

The following table lists the covenants under the Revolving Facilities and the senior unsecured notes, and the compliance therewith as at December 31, 2015.

Covenant Description		**Position as at December 31, 2015**
Revolving Facilities - Financial Covenants	**Maximum Ratio**	
Senior debt to Capitalization[(1) (2)]	0.65:1.00	0.44:1.00
Senior debt to Bank EBITDA[(1) (5)]	5.25:1.00	2.97:1.00
Total debt to Bank EBITDA[(3) (5)]	5.25:1.00	2.97:1.00
Senior Unsecured Notes - Debt Incurrence Covenant	**Minimum Ratio**	
Fixed charge coverage[(4)]	2:50:1.00	5.63:1.00

(1) "Senior debt" is defined as our principal amount of bank loan and long-term notes.
(2) "Capitalization" is defined as the sum of our principal amount of bank loan, long-term notes and shareholders' equity.
(3) "Total debt" is defined as the sum of our principal amount of bank loan, long-term notes, and certain other liabilities identified in the credit agreement.
(4) Fixed charge coverage is computed as the ratio of financing costs excluding accretion on asset retirement obligations to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended December 31, 2015 was $629 million.
(5) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing costs, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange and stock based compensation), and acquisition and disposition activity (excluding acquisition-related costs incurred) and is calculated based on a trailing twelve month basis.

On December 8, 2015, we reached an agreement with the lending syndicate to amend the financial covenants as follows: a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2015 up to and including December 31, 2017, and 0.55:1.00 thereafter; b) the maximum Senior Debt to Bank EBITDA ratio will be 5.25:1.00 for the period December 31, 2015 up to and including December 31, 2017, and 3.50:1.00 thereafter; and c) the maximum Total Debt to Bank EBITDA will be 5.25:1.00 for the period December 31, 2015 up to and including December 31, 2017, 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 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 December 31, 2015 and the accounting treatment thereof is disclosed in note 19 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 February 28, 2016, we had 210,688,856 common shares and no preferred shares issued and outstanding. During the year ended December 31, 2015, shares were issued through an equity financing, the dividend reinvestment plan 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 December 31, 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	**$ 267,838**	$ 267,838	$ —	$ —	$ —
Bank loan(1) (2)	**256,749**	—	—	256,749	—
Long-term notes(2)	**1,623,658**	—	—	8,858	1,614,800
Interest on long-term notes	**620,144**	94,064	188,129	186,969	150,982
Operating leases	**50,305**	8,063	16,501	15,589	10,152
Processing agreements	**52,147**	9,219	10,340	9,043	23,545
Transportation agreements	**75,392**	13,910	24,556	23,371	13,555
Total	**$ 2,946,233**	$ 393,094	$ 239,526	$ 500,579	$ 1,813,034

(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 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 December 31, 2015, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 3 and 4 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with GAAP requires management to make judgments and estimates that affect the financial results of the Company. The financial and operating results of Baytex incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated future recoverable value of petroleum and natural gas properties;
- estimated depletion and depreciation that are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves that Baytex expects to recover in the future;
- estimated fair value of oil and gas properties and exploration and evaluation assets from business combinations;

- estimated fair value of financial derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of share-based compensation related to our Share Award Incentive Plan and related performance conditions and forfeiture rates; and
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

Baytex employs individuals skilled in making such estimates and ensures those responsible have the most accurate information available. Further, approved budgets and prior period estimates are also reviewed and analyzed against actual results to ensure appropriate decisions are made for future estimates and outlooks. Actual results could differ materially if various assumptions or estimates do not turn out as expected.

CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

International Financial Reporting Standards ("IFRS") 15 "Revenue from Contracts with Customers" is effective January 1, 2018 and will supersede IAS 11 "Construction Contracts" and IAS 18 "Revenue" and related interpretations. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The new standard also requires disclosures on the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The Company has not yet adopted IFRS 15 and is evaluating its impact on the consolidated financial statements.

Financial Instruments

IFRS 9 "Financial Instruments" replaces IAS 39 "Financial Instruments: Recognition and Measurement", which eliminates the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. In November 2013, the IASB amended IFRS 9 to include the new general hedge accounting model which remains optional, allows more opportunities to apply hedge accounting, and will be effective on January 1, 2018 and applied retroactively to each period presented. The Company has not yet adopted IFRS 9 and is evaluating its impact on the consolidated financial statements.

Leases

IFRS 16 "Leases" replaces IAS 17 "Leases" and is effective January 1, 2019 with early adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers". The new standard will bring most leases on-balance sheet for lessees. The Company has not yet adopted IFRS 16 and is evaluating its impact on the consolidated financial statements.

2016 GUIDANCE

As an industry, we continue to face unprecedented challenges due to the continued global oversupply of crude oil. We are committed to preserving financial liquidity through this downturn. In 2016, we are targeting capital expenditures to approximate funds from operations in order to minimize additional bank borrowings. In addition, we may contemplate minor non-core asset sales.

Our original 2016 production guidance was 74,000 to 78,000 boe/d with budgeted exploration and development expenditures of $325 to $400 million. This budget contemplated ramping up activity in Canada in the second half of 2016.

Based on the forward strip for the remainder of 2016, we do not plan to execute our heavy oil development program this year. We will forgo drilling 12 net wells at Peace River and 24 net wells at Lloydminster. In addition, we are proactively shutting-in approximately 7,500 bbl/d of low or negative margin heavy oil production in order to optimize the value of our resource base and maximize our funds from operations. Should netbacks improve, we have the ability to restart these wells within one month. We currently anticipate that this production will be brought back on-line mid-year.

In the Eagle Ford, we now anticipate a reduced pace of development in 2016 with approximately four to five drilling rigs (six drilling rigs in fourth quarter of 2015) and one to two frac crews (two frac crews in the fourth quarter of 2015) working on our lands. At this pace, we anticipate bringing approximately 30 net wells on production in 2016 (previously 35 to 40 net wells).

We now anticipate 2016 exploration and development expenditures of $225 to $265 million, of which approximately 95% will be invested in the Eagle Ford. At the mid-point, this reflects a 33% reduction in capital spending for 2016 relative to our initial expectation of $325 to $400 million and a 53% reduction relative to 2015 capital expenditures of $521 million. Our 2016 program will remain flexible and allows for adjustments to spending based on changes in the commodity price environment.

Taking into account the shut-in heavy oil volumes and a reduced capital program, we have revised our production guidance range for 2016 to 68,000 to 72,000 boe/d. Our revised production guidance represents an approximate 5% reduction to our original guidance, excluding the impact of shut-in volumes. This compares to a 33% reduction in our capital budget, demonstrating the continued strong performance of our assets. Based on the mid-point of our production guidance range, approximately 55% of our production is expected to be generated in the Eagle Ford with the remaining 45% coming from our Canadian assets.

Production during the first quarter of 2016 is expected to average 73,000 to 75,000 boe/d.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share amounts)		**2015**		2014
Revenues, net of royalties	**$**	**888,447**	$	1,529,897
Net income (loss)	**$**	**(1,133,651)**	$	(132,807)
Per common share - basic	**$**	**(5.72)**	$	(0.89)
Per common share - diluted	**$**	**(5.72)**	$	(0.89)
Total assets	**$**	**5,488,498**	$	6,230,596
Total bank loan and long-term notes	**$**	**1,854,929**	$	2,062,344
Cash dividends or distributions declared per common share	**$**	**0.80**	$	2.64
Average wellhead prices, net of blending costs ($/boe)	**$**	**35.40**	$	66.54
Total production (boe/d)		**84,648**		78,395

QUARTERLY FINANCIAL INFORMATION

	2015				2014			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**230,200**	268,625	345,432	285,615	472,394	634,415	476,404	385,809
Net income (loss)	**(412,924)**	(517,856)	(26,955)	(175,916)	(361,816)	144,369	36,799	47,841
Per common share - basic	**(1.96)**	(2.49)	(0.13)	(1.04)	(2.16)	0.87	0.27	0.38
Per common share - diluted	**(1.96)**	(2.49)	(0.13)	(1.04)	(2.16)	0.86	0.27	0.38

FOURTH QUARTER OF 2015

Our production for the three months ended December 31, 2015 was 81,110 boe/d, a decrease of 11,161 boe/d as compared to 92,271 boe/d for the fourth quarter of 2014. The declines are due to reduced capital spending, non-core dispositions and uneconomic production we have shut-in. The price of WTI decreased by US$30.96/bbl, or 42%, to US$42.18/bbl in the fourth quarter of 2015 compared to the same period in 2014. Funds from operations were $93.1 million, bringing total funds from operations for the year to $516.4 million. Net loss of $410.0 million in the fourth quarter of 2015 increased from a net loss of $361.8 million for the same period in 2014 due to lower operating netbacks and a larger impairment in the current period.

	Three Months Ended December 31	
Benchmark Averages	**2015**	2014
WTI oil (US$/bbl)	**42.18**	73.14
WCS heavy (US$/bbl)	**27.69**	58.90
Heavy oil differential	**35%**	20%
CAD/USD exchange rate	**1.3353**	1.1378
Edmonton par oil ($/bbl)	**52.94**	75.69
LLS (US$/bbl)	**43.33**	76.34
AECO gas price ($/mcf)	**2.65**	4.01
NYMEX gas price (US$/mmbtu)	**2.27**	4.00

	Three Months Ended December 31					
	2015			2014		
($ thousands, except as noted)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Heavy oil (bbl/d)	**31,733**	**—**	**31,733**	43,186	—	43,186
Light oil and condensate (bbl/d)	**1,600**	**23,330**	**24,930**	2,494	24,422	26,916
NGL (bbl/d)	**973**	**8,023**	**8,996**	1,381	6,717	8,098
Natural gas (mcf/d)	**39,122**	**53,586**	**92,708**	43,048	41,380	84,428
Total production (boe/d)	**40,826**	**40,284**	**81,110**	54,236	38,035	92,271
Baytex Average Sales Prices						
Canadian heavy oil ($/bbl)[1]	**$ 24.41**	**$ —**	**$ 24.41**	$ 53.34	$ —	$ 53.34
Light oil and condensate ($/bbl)	**47.84**	**50.33**	**50.17**	70.77	77.86	77.20
NGL ($/bbl)	**19.93**	**16.90**	**17.23**	33.31	26.99	28.07
Natural gas ($/mcf)	**2.36**	**3.05**	**2.76**	3.89	4.36	4.12
Weighted average ($/boe)[2]	**$ 23.59**	**$ 36.56**	**$ 30.03**	$ 49.66	$ 59.50	$ 53.72
Operating netback ($/boe)						
Oil and natural gas revenues	**$ 23.59**	**$ 36.56**	**$ 30.03**	$ 49.66	$ 59.50	$ 53.72
Other income	**—**	**—**	**0.11**	—	—	0.76
Less:						
Royalties	**2.72**	**10.56**	**6.61**	7.94	17.56	11.90
Operating expenses	**12.27**	**7.23**	**9.76**	14.76	10.36	12.95
Transportation expenses	**2.87**	**—**	**1.45**	3.51	—	2.07
Operating netback	**$ 5.73**	**$ 18.77**	**$ 12.32**	$ 23.45	$ 31.58	$ 27.56
Financial derivatives gain	**—**	**—**	**4.09**	—	—	6.48
Operating netback after financial derivatives	**$ 5.73**	**$ 18.77**	**$ 16.41**	$ 23.45	$ 31.58	$ 34.04
Capital Expenditures						
Exploration and development	**$ 8,804**	**$ 131,992**	**$ 140,796**	$ 65,234	$ 149,463	$ 214,697
Acquisitions, net of divestitures	**$ (593)**	**$ 19**	**$ (574)**	$ (42,212)	$ 6,546	$ (35,666)

(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.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2015 with the same period in 2014:

- Total production for the fourth quarter of 2015 of 81,110 boe/d decreased by 12%, or 11,161 boe/d, from the same period in 2014, with 3,900 boe/d associated with declines from non-core dispositions and uneconomic production we have shut-in.
- FFO for the fourth quarter of 2015 was $93.1 million ($0.44 per basic share), a 62% decrease from $245.5 million ($1.47 per basic share) in the fourth quarter of 2014.
- WTI oil averaged US$42.18/bbl for the fourth quarter of 2015, a 42% decrease from the average WTI price of US$73.14/bbl in the fourth quarter of 2014.
- Our average realized heavy oil price during the fourth quarter of 2015 was $24.41/bbl, or 66% of WCS, compared to $53.34/bbl, or 80% of WCS, in the fourth quarter of 2014. This decrease was due to a lower WTI price partially offset the weakening of the Canadian dollar compared to the fourth quarter of 2014.

- Total petroleum and natural gas revenues for the fourth quarter of 2015 were $230.2 million, a decrease of $242.2 million from the same period in 2014. Canadian revenues totaled $93.9 million, a decrease of $163.9 million from the fourth quarter of 2014 due to lower crude oil prices. In the U.S., the Eagle Ford properties contributed $135.5 million of revenue for the three months ended December 31, 2015, a decrease of $72.7 million from the same period in 2014.
- Operating expenses for the fourth quarter of 2015 of $72.9 million decreased $37.0 million compared to the same period in 2014 primarily due to lower production volumes associated with our Canadian assets combined with cost reductions achieved across all operations. Operating expenses per boe decreased by $3.19/boe from the fourth quarter of 2014 to $9.76/boe in the current period due to cost savings initiatives.
- General and administrative expenses for the three months ended December 31, 2015 were $12.8 million, a decrease of $4.2 million from the same period in 2014 due to reductions to staffing levels to coincide with lower activity levels combined with a reduction in discretionary spending. On a per boe basis, general and administrative expenses decreased by $0.28/boe from the fourth quarter of 2014 to $1.72/boe due to cost controls and the low incremental overhead associated with the acquired Eagle Ford assets.
- Financing costs for the fourth quarter of 2015 of $27.9 million increased $0.6 million as compared to the same period in 2014 due to higher interest expense on U.S. dollar denominated debt as the Canadian dollar weakened against the U.S. dollar offset by lower borrowings on the credit facilities.
- Realized gains on financial derivative contracts totaled $30.5 million for the three months ended December 31, 2015, a decrease of $24.5 million from the same period in 2014 mainly due to higher oil volumes hedged in 2014 as both periods saw a significant drop in WTI prices to levels below those set in our fixed price contracts.
- Unrealized gains on financial derivative contracts totaled $37.9 million for the fourth quarter, a decrease of $91.5 million from the same period in 2014 due to larger decline in prices during the fourth quarter of 2014 and higher oil volumes hedged.
- Depletion expense totaled $163.8 million for the three months ended December 31, 2015, as compared to $176.4 million in the same period of 2014 due to declining production volumes. The depletion rate per boe for the fourth quarter of 2015 remained consistent at $21.12/boe compared to $20.78/boe for the same period in 2014.
- Due to the further decline in commodity prices, we have recorded a $545.3 million impairment charge in the fourth quarter of 2015 as compared to the $449.6 million in the same period in 2014. The impairment relates to $499.6 million of oil and gas properties associated with the Eagle Ford acquisition and $45.7 million of impairment recognized prior to the disposition of non-core assets in Canada.
- Capital expenditures related to exploration and development of $140.8 million were incurred in the fourth quarter of 2015, a decrease of $73.9 million from the same period in 2014. The decrease was mainly in response to the drop in commodity prices during 2015 compared to 2014. We drilled 12.6 net wells in the fourth quarter of 2015 (all in the Eagle Ford), compared to 28.3 net wells (12.9 in Canada and 15.4 in Eagle Ford) during the same period in 2014.

RISK FACTORS

Baytex management is focused on long-term strategic planning and has identified the key risks, uncertainties and opportunities associated with our business that can impact the financial results. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2015 under the "Risk Factors" section.

Volatility of Oil and Natural Gas Prices

Our financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in the shut in of currently producing wells, a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

Our reserves as at December 31, 2015 are estimated using forecast prices and costs. These prices are above current crude oil and natural gas prices. If crude oil and natural gas prices stay at current levels, our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices decline further, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

Debt Service and Refinancing

We are required to comply with covenants under the Revolving Facilities and the our senior unsecured notes. In the event that we do not comply with these covenants, our access to capital (including our ability to make borrowings under our Revolving Facilities) could be restricted or repayment could be required on an accelerated basis by our lenders.

Our existing Revolving Facilities and any replacement facilities may not provide sufficient liquidity. We currently have Revolving Facilities in the amount of $800 million plus US$200 million. The amounts available under our existing Revolving Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our Revolving Facilities will be adequate for our future financial obligations, including our future capital expenditure program, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Revolving Facilities are not extended before June 2019, indebtedness under the Revolving Facilities will be repayable at that time. There is also a risk that the Revolving Facilities will not be renewed for the same amount or on the same terms.

Access to Capital Markets

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future shareholders.

Our ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular and our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

Non-operating Agreements in the U.S.

Marathon Oil EF LLC ("Marathon Oil"), a wholly-owned subsidiary of Marathon Oil Corporation, is the operator of a substantial majority of our Eagle Ford acreage and we will be reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interests and the collective best interests of all of the working interest owners of this acreage, which may not be in our best interests. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities operated by Marathon Oil will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- Marathon Oil's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. If we are not willing or are unable to fund our capital expenditure requirements relating to our Marathon Oil-operated drilling locations, our interests in our drilling locations may be diluted or forfeited.

Variations in Interest Rates and Foreign Exchange Rates

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease to the market price of our common shares.

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our senior unsecured notes are denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

Credit Risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flows and financial position.

Hedging Program

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. We also use derivative instruments in various operational markets to optimize our supply or production chain. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and may also result in royalties being paid on a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

Additional Business Risks

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; technology; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; information systems; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; phased growth execution; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial and state legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Although Baytex believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on Baytex's business, financial condition, results of operations and prospects.

Climate Change Regulation

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation that is enacted in jurisdictions where we have operations. A number of federal, provincial and state governments have announced their intention to regulate greenhouse gases and certain air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases there are few technical details regarding the implementation and coordination of these plans. The Canadian federal government has stated that it will work with the provinces of Canada to come up with a national strategy and it remains unclear what approach the United States federal government will take. Currently, certain provinces and states, including Alberta and British Columbia, have implemented greenhouse gas emission legislation that impacts areas in which we operate and Alberta has announced a new climate change policy which is expected to include a carbon tax. It is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2015 under the "Industry Conditions - Climate Change Regulation" section.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2015, an evaluation was conducted of the effectiveness of Baytex's “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that Baytex's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that Baytex files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that Baytex's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The President and Chief Executive Officer and Chief Financial Officer of Baytex (collectively, the “certifying officers”) are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for Baytex. Disclosure controls and procedures are designed to provide reasonable assurance that (i) material information relating to Baytex is made known to the certifying officers by others, particularly during the period in which public filings are being prepared and (ii) information required to be disclosed by Baytex in filings submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Baytex's financial statements for external reporting purposes in accordance with Canadian GAAP.

Due to inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Additionally, projections of any evaluations of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with Baytex's policies and procedures. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015 based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2015. The effectiveness of Baytex's internal control over financial reporting as of December 31, 2015 has been audited by Deloitte LLP, as reflected in their report for 2015.

Baytex previously excluded Aurora Oil & Gas Limited, which was acquired through a business combination on June 11, 2014, from the Company's evaluation of disclosure controls and procedures and internal controls over financial reporting as permitted by applicable securities laws in Canada and the U.S. During the second quarter of 2015, the Company completed the evaluation and integration of the disclosure controls and, procedures and internal controls over financial reporting of Aurora Oil & Gas Limited. No material changes were made to our internal control over financial reporting during the year ended December 31, 2015.

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 ability to reduced our fixed operating costs; our expectation that we will receive a refund of Canadian cash income taxes during 2016 and the amount thereof; the proposed reassessment of our tax filings by the Canada Revenue Agency; the potential taxes owing and reduction of non-capital losses if the reassessment by the Canada Revenue Agency is successful; our intention to defend the proposed reassessments if issued by the Canada Revenue Agency; our view of our tax filing position; the 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; the existence, operation and strategy of our risk management program; the impact of the adoption of new accounting standards on our financial results; our target for 2016 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings; the possibility of non-core asset sales; our expectations for annual average production rate and exploration and development capital budget for 2016 (both original and revised); our expectation that we will not proceed with our 2016 heavy oil development program; the number of drilling rigs and frac crews working on our Eagle Ford lands during 2016; the portion of our 2016 capital budget to be invested in the Eagle Ford; the number of net wells to be brought on production in the Eagle Ford during 2016; the geographic breakdown of our 2016 annual production; our expectations for the average production rate in Q1/2016; and our expectation that we are in material compliance with environmental legislation. 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; refinancing risk for existing debt and debt service costs; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; a downgrade of our credit ratings; risks associated with properties operated by third parties; 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 risks; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; 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 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.