BAYTEX

ENERGY CORP.

2016 / ANNUAL REPORT

OPERATING AREAS

TABLE OF CONTENTS

SUMMARY

	Years Ended December 31, 2016	Years Ended December 31, 2015
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*		
Petroleum and natural gas sales	$ 780,095	$ 1,121,424
Funds from operations[1]	276,251	516,417
Per share – basic	1.30	2.61
Per share – diluted	1.30	2.61
Net income (loss)	(485,184)	(1,142,880)
Per share – basic	(2.29)	(5.77)
Per share – diluted	(2.29)	(5.77)
Exploration and development	224,783	521,039
Acquisitions, net of divestitures	(63,120)	1,648
Total oil and natural gas capital expenditures	$ 161,663	$ 522,687
Bank loan[2]	$ 191,286	$ 256,749
Long-term notes[2]	1,584,158	1,623,658
Long-term debt	1,775,444	1,880,407
Working capital (surplus) deficiency	(1,903)	169,498
Net debt[3]	$ 1,773,541	$ 2,049,905
OPERATING		
Daily production		
Heavy oil (bbl/d)	23,586	34,974
Light oil and condensate (bbl/d)	21,377	25,887
NGL (bbl/d)	9,349	8,492
Total oil and NGL (bbl/d)	54,312	69,353
Natural gas (mcf/d)	91,182	91,766
Oil equivalent (boe/d @ 6:1)[4]	69,509	84,648
Benchmark prices		
WTI oil (US$/bbl)	43.33	48.79
WCS heavy oil (US$/bbl)	29.49	35.26
Edmonton par oil ($/bbl)	53.01	57.20
LLS oil (US$/bbl)	43.82	51.50
Baytex average prices (before hedging)		
Heavy oil ($/bbl)[5]	26.46	32.23
Light oil and condensate ($/bbl)	50.32	55.75
NGL ($/bbl)	17.16	16.91
Total oil and NGL ($/bbl)	34.25	39.13
Natural gas ($/mcf)	2.69	3.08
Oil equivalent ($/boe)	30.29	35.40
CAD/USD noon rate at period end	1.3427	1.3840
CAD/USD average rate for period	1.3256	1.2811

	Years Ended	
	December 31, 2016	December 31, 2015
COMMON SHARE INFORMATION		
TSX		
Share price (Cdn$)		
High	9.04	24.87
Low	1.57	3.50
Close	6.56	4.48
Volume traded (thousands)	1,677,986	652,044
NYSE		
Share price (US$)		
High	7.14	20.10
Low	1.08	2.50
Close	4.48	3.24
Volume traded (thousands)	707,973	375,660
Common shares outstanding (thousands)	233,449	210,583

Notes:

(1) *Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2016.*

(2) *Principal amount of instruments.*

(3) *Net debt is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan.*

(4) *Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

(5) *Heavy oil prices exclude condensate blending.*

Advisory Regarding Forward-Looking Statements and Initial Production Rates

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our liquidity and financial capacity; our Eagle Ford assets, including our assessment that it is a premier oil resource play, the cost to drill, complete and equip a well, initial production rates from new wells, the performance of wells drilled in the Eagle Ford in Q1/2017 and the number of drilling rigs and frac crews working on our lands during 2017; our recently completed acquisition at Peace River, including that it will drive efficiencies and synergies in our operations and that it significantly enhances opportunities for future growth; our annual average production rate for 2017; our exploration and development capital expenditure budget for 2017; the breakdown of our 2017 capital expenditure budget by geographic area; and our 2016-2017 exit production organic growth rate. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that they can be profitably produced in the future. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

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

Non-GAAP Financial and Capital Management Measures

Funds from operations is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities adjusted for changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

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

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

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

2016 was a year about delivering on our commitments in a difficult commodity price environment. The global oversupply of crude oil weighed heavily on the market as OPEC continued to favour a market share strategy for the majority of the year before coming to a new production quota agreement on November 30, 2016. It was imperative that we remained steadfast in our plan to maintain financial liquidity, reduce costs across all facets of our business, and deploy our capital effectively. In spite of the persistent low oil and gas prices, we were able to strengthen our financial liquidity, reduce our overall debt, and acquire a strategic asset in Peace River. The acquisition not only adds production, but more than doubles our land base and drilling inventory in the area.

Our operating results were in line with guidance, achieving annual average production of 69,509 boe/d while spending $225 million in capital. We targeted capital expenditures to approximate our funds from operations. We exceeded this goal, with our funds from operations totaling $276 million, generating $51 million of excess cash flow. We also disposed of certain non-core assets in Canada and the Eagle Ford for net proceeds of $63 million and we achieved a reduction in cash costs of 8% on a boe basis. All of this contributed to reducing our total net debt at the end of the year to $1.8 billion, a reduction of 13% year-over-year. At the end of the first quarter, we reached agreement with our lenders to amend our credit facilities to provide us with increased financial flexibility. We also delivered on our commitment to minimize any additional bank borrowings, remaining approximately two-thirds undrawn today on our US$575 million credit facilities.

Our Eagle Ford asset, one of the premier oil resource plays in North America, provides the highest cash netbacks in our portfolio and contains a world-class inventory of development prospects. During 2016, we continued our development activity, directing 88% of our exploration and development expenditures to this area. We commenced production from 36 net wells and established 30-day initial production rates of approximately 1,300 boe/d, representing a 20% improvement over 2015. In the fourth quarter of 2016, production averaged 33,432 boe/d. Our drilling, completions and equipping costs per well were also reduced to a record low US$4.5 million during the quarter – down 20% from $5.6 million in the first quarter of the year. These record low well costs were achieved despite increasing the number of frac stages and proppant loading. Two recently completed pads utilizing higher intensity fracs in the crude oil window of our Longhorn acreage have shown a substantial improvement in production rates compared to wells drilled previously. Toward year end we increased our rig activity and expect to run four to five rigs and two completion crews throughout 2017.

In Canada, low oil prices at the outset of the year required us to defer development in both our Peace River and Lloydminster regions. We also proactively shut-in 7,500 boe/d of low or negative margin heavy oil production in the first quarter. As oil prices improved, we reinitiated production from these wells by mid-year.

In November, we announced the strategic acquisition of additional heavy oil assets in Peace River, located immediately adjacent to our existing Peace River assets. The acquisition more than doubled our land base in the area and enables further efficiencies and synergies in our operations and significantly enhances our opportunities for future growth. We closed the acquisition on January 20, 2017 for total consideration of $65 million. At the time of closing, the assets were producing 3,000 boe/d with an additional 3,000 boe/d shut-in.

We are excited to get back to work in Canada in 2017 with an active drilling program planned at both Peace River and Lloydminster. The results to-date from this program have been very promising.

We believe that by conducting all aspects of our operations in a responsible and environmentally sensitive manner, we create long-term value for all stakeholders. Developing crude oil and natural gas resources requires long-term commitment. Collaboration with a broad range of engaged stakeholders is important to achieve enduring success in resource development. Accordingly, we have continued our focus on stakeholder engagement, furthering the progress of our Good Neighbour Program throughout our field operations. This program strives to create social and economic benefits for the community while mitigating the impacts related to our operations; it is a real-life expression of responsible development. In the end, everyone benefits from environmentally responsible development that produces reliable energy at a reasonable cost.

We continue to strive for excellence in our health, safety and environment initiatives and we expect to publish our 2016 Corporate Responsibility Report in the fall of 2017.

Looking Forward

As we look forward into 2017, we are now highly focused on two key priorities. The first is to arrest production declines through a highly efficient capital development program in both the Eagle Ford and Canada. And secondly, we will place a high priority on managing our debt position.

We have budgeted exploration and development capital expenditures of $300 to $350 million for 2017. For the full-year, approximately 70% of our planned capital expenditures will be directed to our Eagle Ford operations and the balance will be in Canada, largely toward our heavy oil assets at Peace River and Lloydminster. Our 2017 capital program is off to a strong start driven by larger fracture stimulations in the oil window of the Eagle Ford, the commencement of heavy oil drilling operations at Peace River and Lloydminster and increasing production from our recently acquired assets at Peace River. Overall, we expect to grow production 3-4% on an exit rate basis from 2016 to 2017 with average annual production of 66,000 to 70,000 boe/d.

Baytex's success is due to our dedicated and talented team of employees who align with our strategy, consistently deliver on our plans and drive the creation of shareholder value. Complementing our leadership team and committed employees, our Board of Directors is an indispensable source of guidance and support which contribute greatly to our success.

We look forward to executing our plans for 2017 for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

James L. Bowzer
Chief Executive Officer

Edward D. LaFehr
President

March 7, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2016 and 2015. This information is provided as of March 6, 2017. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the year ended December 31, 2016 ("2016") have been compared with the results for the year ended December 31, 2015 ("2015") and the results for the three months ended December 31, 2016 ("Q4/2016") have been compared with the results for the three months ended December 31, 2015 ("Q4/2015"). 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, 2016 and 2015, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2016. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

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

CAPITAL MANAGEMENT MEASURES

In this MD&A, we refer to certain capital management measures as outlined in note 22 to the consolidated financial statements, such as funds from operations and net debt which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations and net debt are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

We consider funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and potential dividends. We believe that this measure provides a meaningful assessment of our operations by eliminating certain non-cash charges. 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 to funds from operations.

	Years Ended December 31	
($ thousands)	**2016**	2015
Cash flow from operating activities	**$ 247,365**	$ 549,420
Change in non-cash working capital	**23,270**	(43,891)
Asset retirement expenditures	**5,616**	10,888
Funds from operations	**$ 276,251**	$ 516,417

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity.

The following table summarizes our calculation of net debt.

($ thousands)	December 31, 2016	December 31, 2015
Bank loan[1]	$ 191,286	$ 256,749
Long-term notes[1]	1,584,158	1,623,658
Working capital (surplus) deficiency[2]	(1,903)	169,498
Net debt	$ 1,773,541	$ 2,049,905

(1) Principal amount of instruments expressed in Canadian dollars.
(2) Working capital is current assets less current liabilities (excluding current financial derivatives and onerous contracts).

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by GAAP. While operating netback and EBITDA 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. We believe that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze against prior periods on a comparable basis.

Operating Netback

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

	Years Ended December 31	
($ thousands)	2016	2015
Petroleum and natural gas revenue	$ 780,095	$ 1,121,424
Blending expense	(9,622)	(27,830)
Oil and natural gas revenue	770,473	1,093,594
Royalties	178,116	241,425
Operating expense	240,705	320,187
Transportation expense	28,257	53,127
Operating netback	323,395	478,855
Realized financial derivative gain	96,929	197,545
Operating netback after realized financial derivatives gain	$ 420,324	$ 676,400

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants. The following table reconciles net income (loss) to Bank EBITDA.

	Years Ended December 31	
($ thousands)	2016	2015
Net income (loss)	$ (485,184)	$ (1,142,880)
Plus:		
Financing and interest	114,199	111,660
Unrealized foreign exchange (gain) loss	(41,436)	213,999
Unrealized financial derivatives loss	140,136	54,816
Current income tax (recovery) expense	(8,042)	8,907
Deferred income tax (recovery)	(264,561)	(353,053)
Depletion and depreciation	508,309	661,858
Impairment	423,176	1,038,554
Disposition of oil and gas properties (gain) loss	(43,907)	1,519
Non-cash items(1)	29,974	33,348
Bank EBITDA	$ 372,664	$ 628,728

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

YEAR END HIGHLIGHTS

2016 presented many challenges for the oil and gas industry and for Baytex. With the low commodity price environment, we made significant adjustments to our business to maintain strong levels of financial liquidity. We reduced our capital spending, emphasized cost reductions in all facets of the business, renegotiated our credit facilities, raised equity to fund an acquisition that closed in early 2017 and disposed of certain non-core assets.

Production for the year averaged 69,509 boe/d, which was consistent with our guidance of 68,000 – 70,000 boe/d. In the Eagle Ford, production averaged 36,573 boe/d, an 8% decrease from 2015. The reduced number of completions combined with the sale of approximately 1,000 boe/d of operated production contributed to the decrease on our Eagle Ford assets from 2015. In Canada, production was 32,936 boe/d for 2016 compared to 44,691 boe/d in 2015. Due to the low price environment, we deferred all operated heavy oil drilling including development and stratigraphic test wells. This reduced level of activity caused production to decrease from 2015. In addition, we shut in production with low or negative margins for part of the year which reduced annual average production by approximately 2,400 boe/d.

Oil prices were at multi-year low levels in 2016 with continued over supply and high inventory levels. In Q1/2016, the price of West Texas Intermediate light oil (“WTI”) averaged US$33.45/bbl. Prices stabilized in Q2/2016 and Q3/2016 with WTI averaging approximately US$45/bbl before the Organization of the Petroleum Exporting Countries (“OPEC”) announcement on November 30, 2016 which resulted in WTI oil prices rising above US$50/bbl for the last part of 2016. WTI averaged US$43.33/bbl during 2016 compared to US$48.79/bbl in 2015 representing a decrease of $5.48/bbl. Natural gas prices also decreased from 2015 with AECO decreasing 24% from $2.74/mcf in 2015 to $2.09/mcf in 2016 and NYMEX decreasing 8% from US$2.66/mmbtu in 2015 to US$2.46/mmbtu in 2016. The large AECO discount to Henry Hub is due to the oversupply of gas in the Western Canadian Sedimentary Basin. The decrease in commodity prices during 2016 reduced our revenue per boe to $30.29/boe from $35.40/boe for 2015.

During 2016, we successfully reduced our cost structure to help mitigate some of the commodity price decrease. In the Eagle Ford, the costs to drill, complete and equip our wells decreased throughout the year and averaged approximately US$4.5 million per well in Q4/2016, as compared to US$8.2 million per well in late 2014. Operating expenses per boe were reduced 9% to $9.46/boe for 2016, as compared to $10.36/boe for 2015, and transportation expenses per boe decreased 35% to $1.11/boe in 2016, as compared to $1.72/boe in 2015. These reductions reflect a combination of a lower overall cost structure combined with the lower cost Eagle Ford assets representing a larger percentage of our total production. General and administrative expenses were reduced to $50.9 million in 2016 from $59.4 million in 2015.

Throughout 2016, we targeted our capital expenditures to approximate FFO in order to minimize additional bank borrowings. For 2016, our FFO totaled $276.3 million compared to capital expenditures of $224.8 million. Capital expenditures were focused on our Eagle Ford assets where we invested $198.9 million to drill 127 (36.9 net) wells and commenced production from 123 (36.3 net) wells. In Canada, capital expenditures were limited to $25.9 million with drilling limited to 15 (4.0 net) wells mainly focused on non-operated lands in Lloydminster.

In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and also completed a $115 million equity financing to fund the acquisition. The equity financing closed on December 12, 2016 with 21.9 million shares being issued for proceeds of $109.9 million (net of issue costs). The acquisition closed subsequent to year end on January 20, 2017.

We generated FFO of $276.3 million ($1.30 per basic and diluted share) during 2016 compared to $516.4 million ($2.61 per basic and diluted share) in 2015. The decrease in FFO is primarily due to lower realized pricing, lower production volumes and lower realized hedging gains.

In 2016, our FFO exceeded our capital expenditures net of asset sales by $115 million. This, along with the proceeds from the equity financing and a decrease in the CAD/USD exchange rate, contributed to our net debt decreasing by $276 million from December 31, 2015 to $1.77 billion at December 31, 2016. We also had approximately $580 million of undrawn credit capacity and are in compliance with all of our financial covenants as at December 31, 2016.

RESULTS OF OPERATIONS

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

Production

	Years Ended December 31					
	2016			2015		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**23,586**	**–**	**23,586**	34,974	–	34,974
Light oil and condensate	**1,407**	**19,970**	**21,377**	1,828	24,059	25,887
NGL	**1,274**	**8,075**	**9,349**	1,070	7,422	8,492
Total liquids (bbl/d)	**26,267**	**28,045**	**54,312**	37,872	31,481	69,353
Natural gas (mcf/d)	**40,015**	**51,167**	**91,182**	40,911	50,855	91,766
Total production (boe/d)	**32,936**	**36,573**	**69,509**	44,691	39,957	84,648
Production Mix						
Heavy oil	**72%**	**–%**	**34%**	79%	–%	41%
Light oil and condensate	**4%**	**55%**	**31%**	4%	61%	31%
NGL	**4%**	**22%**	**13%**	2%	19%	10%
Natural gas	**20%**	**23%**	**22%**	15%	20%	18%

Production for 2016 averaged 69,509 boe/d, an 18% decrease from 2015. U.S. production averaged 36,573 boe/d in 2016, an 8% decrease from 2015 as a result of decreased capital investment and the sale of approximately 1,000 boe/d of operated production in the Eagle Ford. Canadian production of 32,936 boe/d decreased 26%, or 11,755 boe/d, from 2015 with minimal capital investment along with low or negative margin production that was shut-in for part of 2016. The shut-in volumes reduced 2016 average production by approximately 2,400 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

Crude oil was extremely volatile during 2016 as the global over supply of crude oil combined with elevated inventory levels weighed on the price. In Q1/2016, WTI crude oil prices hit a 13-year low of US$26.21/bbl. During Q2/2016 and Q3/2016, prices were stabilized and averaged approximately US$45/bbl. On November 30, 2016, OPEC and non-OPEC countries agreed to production cuts which resulted in oil prices rising above US$50/bbl for the last part of 2016. WTI averaged US$49.29/bbl for Q4/2016, a 10% increase compared to Q3/2016. For 2016, WTI averaged US$43.33/bbl, representing an 11% decrease from the average WTI price of US$48.79/bbl for 2015.

The discount for Canadian heavy oil is measured by the Western Canadian Select (“WCS”) price differential to WTI. For 2016, the WCS heavy oil differential averaged US$13.84/bbl, as compared to US$13.53/bbl for 2015. Over the past year, increased pipeline capacity from Canada to the U.S. Gulf Coast combined with lower overall production levels have helped to stabilize the WCS heavy oil differential.

Natural Gas

Natural gas prices have been driven lower during 2016 compared to 2015 mainly due to production levels exceeding demand. For 2016, the AECO natural gas price averaged $2.09/mcf, a decrease of $0.65/mcf or 24% compared to $2.74/mcf in 2015. The NYMEX natural gas price averaged US$2.46/mmbtu during 2016, representing a decrease of US$0.20/mmbtu or 8% compared to US$2.66/mmbtu in 2015. AECO continues to trade at a significant discount to NYMEX due to the oversupply in Western Canada combined with pipeline constraints.

The following table compares selected benchmark prices and our average realized selling prices for the years ended December 31, 2016 and 2015.

	Years Ended December 31		
	2016	2015	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**43.33**	48.79	(11%)
WTI oil (CAD$/bbl)	**57.44**	62.50	(8%)
WCS heavy oil (US$/bbl)(2)	**29.49**	35.26	(16%)
WCS heavy oil (CAD$/bbl)	**39.09**	45.17	(13%)
LLS oil (US$/bbl)(3)	**43.82**	51.50	(15%)
LLS oil (CAD$/bbl)	**58.08**	65.98	(12%)
CAD/USD average exchange rate	**1.3256**	1.2811	3%
Edmonton par oil ($/bbl)	**53.01**	57.20	(7%)
AECO natural gas price ($/mcf)(4)	**2.09**	2.74	(24%)
NYMEX natural gas price (US$/mmbtu)(5)	**2.46**	2.66	(7%)

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

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

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

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

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

	Years Ended December 31					
	2016			2015		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Canadian heavy oil ($/bbl)(2)	**$ 26.46**	**$ –**	**$ 26.46**	$ 32.23	$ –	$ 32.23
Light oil and condensate ($/bbl)	**46.21**	**50.60**	**50.32**	52.52	55.99	55.75
NGL ($/bbl)	**17.77**	**17.06**	**17.16**	20.80	16.35	16.91
Natural gas ($/mcf)	**2.01**	**3.21**	**2.69**	2.59	3.47	3.08
Weighted average ($/boe)(2)	**$ 24.06**	**$ 35.89**	**$ 30.29**	$ 30.24	$ 41.16	$ 35.40

(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

During 2016, we realized $50.60/bbl for our U.S. light oil and condensate. This was down from $55.99/bbl or approximately 10% from 2015, which is slightly less than the 12% decrease in the LLS benchmark (expressed in Canadian dollars) over the same period. Reduced supply along with increased pipeline capacity have tightened the pricing differential between our realized U.S. light oil and condensate pricing to LLS during 2016 compared to 2015.

Our realized Canadian light oil and condensate price averaged $46.21/bbl for 2016 compared to $52.52/bbl for 2015. This represents a 12% decrease in 2016 which is higher than the 7% decrease in the benchmark Edmonton par price over the same period. Our Canadian realized price decreased slightly more than the benchmark when comparing 2016 to 2015 as a higher percentage of our Canadian light oil production in 2016 was comprised of medium grade crude which has a higher discount to the benchmark price.

In 2016, our realized heavy oil price was $26.46/bbl, a $5.77/bbl decrease from 2015. The decrease in our realized heavy oil price during 2016 is generally consistent with the decrease in the WCS benchmark price (expressed in Canadian dollars) of $6.08/bbl over the same period. Our heavy oil is generally sold at a fixed dollar differential to the benchmark price. Our realized price decreased slightly less than the benchmark as the volumes that were shut-in during part of 2016 had a higher discount to the benchmark price resulting in slightly better price realizations during 2016.

Our Canadian average realized natural gas price was $2.01/mcf for 2016, down 22% from the same period in 2015. The decrease in our realized prices during 2016 was consistent with the decrease in the AECO benchmark of 24% over the same period.

Our U.S. realized natural gas price was $3.21/mcf for 2016, down 7% from 2015 which is consistent with the decrease in the NYMEX benchmark of 7% over the same period.

For 2016, our realized NGL price was $17.16/bbl or 30% of WTI (expressed in Canadian dollars) compared to $16.91/bbl or 27% of WTI in 2015. The change in our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes.

Gross Revenues

	Years Ended December 31					
	2016			2015		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil revenue						
Heavy oil	$ 228,425	$ –	$ 228,425	$ 411,386	$ –	$ 411,386
Light oil and condensate	23,792	369,869	393,661	35,044	491,700	526,744
NGL	8,287	50,416	58,703	8,121	44,286	52,407
Total liquids revenue	260,504	420,285	680,789	454,551	535,986	990,537
Natural gas revenue	29,506	60,178	89,684	38,723	64,334	103,057
Total oil and natural gas revenue	290,010	480,463	770,473	493,274	600,320	1,093,594
Heavy oil blending revenue	9,622	–	9,622	27,830	–	27,830
Total petroleum and natural gas revenues	$ 299,632	$ 480,463	$ 780,095	$ 521,104	$ 600,320	$ 1,121,424

Total oil and natural gas revenues for 2016 of $770.5 million decreased by $323.1 million or 30% from 2015 due to a combination of lower commodity prices and reduced production volumes. Oil and natural gas revenues per boe decreased 14% in 2016 compared to 2015, which accounted for $158 million of the reduction in oil and natural gas revenue year over year. The decrease in production accounts for the remaining $165 million difference in revenue from 2015. Oil and natural gas revenues of $480.5 million in the U.S. decreased $119.9 million from 2015 mainly due to the $5.27/boe decrease in oil and gas revenues per boe resulting from lower commodity prices. In Canada, oil and natural gas revenues for 2016 totaled $290.0 million, a $203.3 million decrease compared to 2015 due to lower production volumes and lower realized prices.

Heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. The cost of blending diluent is recovered in the sale price of the blended product. Our heavy oil transported by rail does not require blending diluent. The purchases and sales of blending diluent are recorded as heavy oil blending expense and revenue, respectively. Heavy oil blending revenue of $9.6 million for 2016 decreased $18.2 million compared to 2015. This decrease is a result of lower heavy oil production in Canada combined with lower overall prices for diluent in 2016 compared to 2015.

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, 2016 and 2015.

	Years Ended December 31					
	2016			2015		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 37,720	$ 140,396	$ 178,116	$ 67,323	$ 174,102	$ 241,425
Average royalty rate(1)	13.0%	29.2%	23.1%	13.6%	29.0%	22.1%
Royalty rate per boe	$ 3.13	$ 10.49	$ 7.00	$ 4.13	$ 11.94	$ 7.81

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

Total royalties for 2016 of $178.1 million decreased by $63.3 million or 26%, from 2015, primarily due to the 29% decline in oil and natural gas revenues. Total royalties decreased less than revenues as the Eagle Ford, which has a higher royalty rate, represented approximately 62% of oil and natural gas revenues in 2016 compared to approximately 55% in 2015. Canadian royalties, which vary with price, decreased to 13.0% of oil and natural gas revenue for 2016 compared to 13.6% of revenue in 2015, primarily due to lower commodity prices. The royalty percentage on our U.S. assets does not vary with price and as a result the 2016 U.S. royalty rate has remained fairly consistent with the 2015 rate.

Operating Expense

	Years Ended December 31					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Operating expense	$ 142,242	$ 98,463	$ 240,705	$ 210,945	$ 109,242	$ 320,187
Operating expense per boe	$ 11.80	$ 7.36	$ 9.46	$ 12.93	$ 7.49	$ 10.36

(1) *Operating expense related to the Eagle Ford assets includes transportation expense.*

Operating expense of $240.7 million for 2016 decreased by $79.5 million or 25%, compared to 2015. Overall operating costs are down as production has decreased in 2016 compared to 2015. Operating expense are also down on a unit of production basis with operating costs decreasing to $9.46/boe for 2016, compared to $10.36/boe for 2015 representing a 9% decrease. In Canada, the impact of our cost savings initiatives along with the benefit of shutting-in higher cost properties for part of 2016 resulted in lower operating expenses per unit of production for 2016 compared to 2015. Also, the lower cost Eagle Ford assets comprise a larger proportion of our overall volumes which has helped reduce our overall operating costs per boe.

U.S. operating expense of $98.5 million for 2016 decreased by $10.8 million compared to 2015 primarily due to the decrease in production. On a unit of production basis, U.S operating expenses for 2016 decreased slightly to $7.36/boe compared to $7.49/boe for 2015. On a U.S. dollar basis, operating expenses per boe decreased 5% in 2016 compared to 2015 but the Canadian dollar weakened against the U.S. dollar which partially mitigated the impact of the operating cost savings expressed in Canadian dollars.

Canadian operating expense of $142.2 million for 2016, decreased by $68.7 million or 33%, compared to 2015. The decrease is a result of lower production volumes combined with realized cost savings across all of our operations. On a per boe basis, Canadian operating expense was $11.80/boe for 2016 down 9% compared to $12.93/boe in

2015. The decrease in 2016 reflects the cost savings initiatives during the year combined with the impact of higher cost production being shut-in for part of 2016.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of heavy oil in Canada to pipeline and rail terminals. The following table compares our transportation expense for the years ended December 31, 2016 and 2015.

	Years Ended December 31					
	2016			2015		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Transportation expense	$ 28,257	$ –	$ 28,257	$ 53,127	$ –	$ 53,127
Transportation expense per boe	$ 2.34	$ –	$ 1.11	$ 3.26	$ –	$ 1.72

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

Transportation expense for 2016 totaled $28.3 million representing a decrease of 47% from $53.1 million in 2015. The decrease is due to lower heavy oil volumes being transported combined with the increased use of lower cost internal trucking. Transportation expense is also down on a per unit of production basis in 2016 to $2.34/boe in Canada compared to $3.26/boe in 2015. The use of lower cost internal trucking and shut-in volumes, which were generally subject to higher transportation charges explains the decrease from 2015.

Blending Expense

Blending expense for 2016 of $9.6 million decreased $18.2 million or 67% compared to $27.8 million for 2015. Consistent with the 65% decrease in heavy oil blending revenue, blending expense decreased due to lower volumes of blending diluent being used combined with the decrease in diluent prices in 2016 compared to 2015.

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 year ended December 31, 2016 and 2015.

	Years Ended December 31		
($ thousands)	2016	2015	Change
Realized financial derivatives gain (loss)			
Crude oil	$ 88,860	$ 235,393	$ (146,533)
Natural gas	8,069	8,549	(480)
Foreign currency	–	(46,397)	46,397
Total	$ 96,929	$ 197,545	$ (100,616)
Unrealized financial derivatives gain (loss)			
Crude oil	$ (122,249)	$ (70,354)	$ (51,895)
Natural gas	(17,887)	968	(18,855)
Foreign currency	–	15,068	(15,068)
Interest and financing(1)	–	(498)	498
Total	$ (140,136)	$ (54,816)	$ (85,320)
Total financial derivatives gain (loss)			
Crude oil	$ (33,389)	$ 165,039	$ (198,428)
Natural gas	(9,818)	9,517	(19,335)
Foreign currency	–	(31,329)	31,329
Interest and financing	–	(498)	498
Total	$ (43,207)	$ 142,729	$ (185,936)

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

The realized financial derivatives gain of $96.9 million for 2016 is a result of crude oil prices being at levels below those set in our fixed price contracts.

The unrealized financial derivatives loss of $140.1 million for 2016 is due to the realization, or reversal, of previous unrealized gains recorded at December 31, 2015 and from the increase in WTI futures price subsequent to December 31, 2015. At December 31, 2016, the fair value of our financial derivative contracts represent a net liability of $29.1 million compared to a net asset of $111.0 million at December 31, 2015.

For 2017, we have entered into hedges on approximately 51% of our net WTI exposure with 10% fixed at US$54.46/bbl and 41% hedged utilizing a 3-way option structure that provide us with downside price protection at approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 33% of our net WCS differential exposure and 57% of our net natural gas exposure.

Baytex had the following commodity financial derivative contracts as at March 6, 2017.

	Period	Volume	Price/Unit(1)	Index
Oil				
3-way option(2)	Jan 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI
Basis swap	Jan 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS
Fixed – Sell	Jan 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI
Fixed – Sell	Jan 2018 to Dec 2018	2,000 bbl/d	US$54.40	WTI
Basis swap(3)	Mar 2017 to Jun 2017	1,000 bbl/d	WTI less US$14.30	WCS
Basis swap(3)	Apr 2017 to Jun 2017	2,000 bbl/d	WTI less US$13.50	WCS
Basis swap(3)	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$14.25	WCS
Natural Gas				
Fixed – Sell	Jan 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX
Fixed – Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX
Fixed – Sell	Jan 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO
Fixed – Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO

(1) *Based on the weighted average price/unit for the remainder of the contract.*
(2) *3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.*
(3) *Contracts entered subsequent to December 31, 2016.*

A full description of our financial derivatives can be found in note 18 to the consolidated financial statements.

Operating Netback

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

	Years Ended December 31										
	2016						2015				
($ per boe except for volume)		Canada		U.S.		Total		Canada		U.S.		Total
Sales volume (boe/d)		32,936		36,573		69,509		44,691		39,957		84,648
Operating netback:												
Oil and natural gas revenues	$	24.06	$	35.89	$	30.29	$	30.24	$	41.16	$	35.40
Less:												
Royalties		3.13		10.49		7.00		4.13		11.94		7.81
Operating expenses		11.80		7.36		9.46		12.93		7.49		10.36
Transportation expenses		2.34		–		1.11		3.26		–		1.72
Operating netback	$	6.79	$	18.04	$	12.72	$	9.92	$	21.73	$	15.51
Realized financial derivatives gain		–		–		3.81		–		–		6.39
Operating netback after financial derivatives gain	$	6.79	$	18.04	$	16.53	$	9.92	$	21.73	$	21.90

Exploration and Evaluation Expense

Exploration and evaluation expense will vary from period to period depending on the expiry of leases and assessment of our exploration programs and assets. Exploration and evaluation expense was $6.0 million for 2016, as compared to $8.8 million for 2015. The decrease in expense in 2016 compared to 2015 is due to lower expiries of undeveloped land.

Depletion and Depreciation

	Years Ended December 31											
	2016						2015					
($ thousands except for per boe)		Canada		U.S.		Total		Canada		U.S.		Total
Depletion and depreciation[1]	$	210,778	$	294,854	$	508,309	$	279,744	$	377,847	$	661,858
Depletion and depreciation per boe	$	17.49	$	22.03	$	20.04	$	17.15	$	25.91	$	21.42

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $508.3 million for 2016, decreased by $153.5 million or 23% from 2015 mainly due to lower production. On a per boe basis, depletion and depreciation expense for 2016 was also down coming in at $20.04/boe, compared to $21.42/boe for 2015. The overall depletion rate has decreased in 2016 as we recorded $709.9 million of impairments on U.S. oil and gas properties in 2015 which reduced the depletable asset base along with the depletion rate per boe.

Impairment

In 2016, we recorded total impairment expense of $423.2 million. This impairment expense includes a $166.6 million impairment on our exploration and evaluation assets in the Eagle Ford, $230.0 million impairment on our oil and gas assets in Peace River and $26.6 million of impairments on an asset located near Lloydminster, which was subsequently disposed of in Q3/2016.

In 2016, we derecognized $166.6 million of exploration and evaluation assets in the Eagle Ford due to changes to our development plan, which resulted in possible reserves being reclassified to contingent resources. The derecognition of exploration and evaluation assets was recorded as an impairment charge.

In our Peace River CGU, we recorded a $230.0 million impairment expense on our oil and gas properties. Due to the low oil price environment, we did not engage in any reserves generating activity on our heavy oil assets in Canada, deferring all operated drilling activity, including development wells and stratigraphic test wells. This reduced level of activity resulted in limited reserves additions, which, when combined with production, economic factors and technical revisions, resulted in a 21% reduction in proved plus probable reserve volumes associated with our Peace River CGU, which resulted in an impairment. The recoverable amount of the Peace River CGU was determined based on their fair value less costs of disposal at December 31, 2016 using the discounted cash flows for proved and probable reserves. In computing the future cash flows of the assets, we made certain assumptions, most significantly about future commodity prices and the discount rate. We assumed a WTI price of approximately US$55.00/bbl in 2017, US$65.00/bbl in 2018 and US$70.00/bbl in 2019. It is possible that commodity prices in those years may be lower than the current estimate which could result in further impairments. Discount rates ranging from 10% to 15% before tax were applied to the cash flows.

In Q3/2016, we recorded a $26.6 million impairment expense in our Lloydminster CGU on assets that were reclassified from oil and gas properties to assets held for sale. The carrying value of the assets that were transferred to assets held for sale, exceeded their fair value, being the sale price, resulting in the impairment.

For 2015, we recorded an impairment expense totaling $1,038.6 million, which was comprised of a $992.9 million impairment on our Eagle Ford assets and $45.7 million impairment related to assets in our Lloydminster CGU. The impairment charge on our Eagle Ford assets were directly attributable to lower commodity prices. The Eagle Ford assets were originally recorded at their fair value at the time of acquisition in June 2014 when the WTI oil price was above US$100/bbl. Commodity prices declined in 2015 along with the future market prices which reduced the estimated future cash flows for our Eagle Ford assets below the carrying amount of the assets. The total impairment for 2015 on our Eagle Ford assets included $282.9 million of remaining goodwill associated with this acquisition along with $710.0 million related to oil and gas properties. In our Lloydminster CGU, we identified certain lands that we no longer anticipated the ability to access, develop and explore, therefore, we recorded an impairment charge of $45.7 million on these assets. The lands were subsequently disposed of in November 2015.

General and Administrative Expense

	Years Ended December 31		
($ thousands except for % and per boe)	2016	2015	Change
General and administrative expense	$ 50,866	$ 59,406	(14%)
General and administrative expense per boe	$ 2.00	$ 1.92	4%

General and administrative ("G&A") expense for 2016 of $50.9 million decreased $8.5 million or 14% from $59.4 million in 2015. The decrease is attributable to reductions in staffing levels commensurate with lower activity levels combined with cost saving efforts. On a per boe basis, G&A expense increased 4% to $2.00/boe from $1.92/boe as production decreased 18% over the period compared to the 14% reduction in G&A expense.

Share-Based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan was $13.9 million for 2016, compared to $24.6 million for 2015. For 2016, compensation expense decreased $10.7 million due to the lower fair value of share awards granted late in 2015 and early in 2016. This lower fair value is a result of a reduction in the Company's share price at grant date for the new grants compared to those issued prior to 2015.

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

For the year ended December 31, 2015 an adjustment of $9.2 million of share-based compensation has been recorded resulting in a revised expense of $24.6 million. Net loss per share (basic and diluted) increased by $0.05 to $5.77 per share from $5.72 per share for the year ended December 31, 2015. For the year ended December 31, 2014 an additional $4.2 million of share-based compensation has been recorded resulting in a revised expense of $31.7 million. Net loss per share (basic and diluted) increased by $0.03 to $0.92 from $0.89 per share for the year ended December 31, 2014. As at December 31, 2014, both deficit and contributed surplus were increased by $8.2 million. A summary of the adjustments are disclosed in note 13 to the consolidated financial statements.

Financing and Interest Expense

Financing and interest expense includes interest on our bank loan and long-term notes, non-cash financing costs and the accretion on our asset retirement obligations.

Financing and interest expense increased slightly to $114.2 million for 2016, compared to $111.7 million in 2015. This increase relates to the interest on our U.S. dollar denominated long-term notes. The Canadian dollar was weaker against the U.S. dollar during 2016 averaging 1.3256 CAD/USD, as compared to 2015 when the exchange rate averaged 1.2811 CAD/USD, which increased the expense during 2016.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan are translated to Canadian dollars on the balance sheet date. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

	Years Ended December 31		
($ thousands except for % and exchange rates)	**2016**	2015	Change
Unrealized foreign exchange loss (gain)	**$ (41,436)**	$ 213,999	(119%)
Realized foreign exchange (gain)	**(1,242)**	(3,286)	(62%)
Foreign exchange loss (gain)	**$ (42,678)**	$ 210,713	(120%)
CAD/USD exchange rates:			
At beginning of period	**1.3840**	1.1601	
At end of period	**1.3427**	1.3840	

The Company recorded an unrealized foreign exchange gain of $41.4 million for 2016 as the Canadian dollar at December 31, 2016 strengthened against the U.S. dollar with a CAD/USD exchange rate of 1.3427 compared to the exchange rate of 1.3840 at December 31, 2015.

The Company realizes foreign exchange gains and losses from day-to-day U.S. dollar denominated transactions in its Canadian entities. For 2016, the Company recorded realized foreign exchange gains of $1.2 million, compared to gains of $3.3 million for 2015.

Other Income/Expense

For 2016, we have other expense of $8.2 million, compared to other income of $8.4 million for 2015. In 2016, we entered into agreements to sublease a portion of our firm transportation commitment and a portion of our office space at a loss. We recorded an expense of $6.7 million on the transportation agreement and $3.5 million on our office space. These expenses represent the difference between the minimum future payments that we are required to make and the estimated recoveries. This was offset by miscellaneous income of $2.0 million. In 2015, we subleased our firm transportation commitment at a higher rate than our contract rate and recognized other income of $8.4 million.

Income Taxes

	Years Ended December 31		
($ thousands)	2016	2015	Change
Current income tax (recovery) expense	$ (8,042)	$ 8,907	$ (16,949)
Deferred income tax (recovery)	(264,561)	(353,053)	88,492
Total income tax (recovery)	$ (272,603)	$ (344,146)	$ 71,543

In 2016, available tax deductions exceeded taxable income which allowed the Company to recover a portion of the prior year current income tax expense. For 2016, this resulted in a current income tax recovery of $8.0 million, an increase of $16.9 million over the current income tax expense of $8.9 million for 2015.

The 2016 deferred income tax recovery of $264.6 million decreased $88.5 million from $353.1 million in 2015. The decrease during 2016 compared to 2015 is due to the higher impairment expense on oil and gas properties recorded in 2015, partially offset by an increase in unrealized loss on financial derivatives and a decrease in the amount of tax pool claims required to shelter the lower taxable income.

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

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

In September 2016, we filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of the CRA; a process that we estimate could take up to two years. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

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

Tax Pools

The Company has Canadian and U.S. 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, we do not expect to pay material amounts of cash income taxes prior to 2020.

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

($ thousands)	December 31, 2016	December 31, 2015
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	$ 198,525	$ 231,168
Canadian development expenditures	250,239	347,014
Canadian exploration expenditures	210	94
Undepreciated capital costs	256,549	339,635
Non-capital losses	151,959	63,064
Financing costs and other	69,025	84,734
Total Canadian tax pools	$ 926,507	$ 1,065,709
U.S. Tax Pools		
Depletion	$ 297,252	$ 383,551
Intangible drilling costs	388,727	439,380
Tangibles	136,969	149,971
Non-capital losses	1,039,782	1,046,951
Other	201,896	65,669
Total U.S. tax pools	$ 2,064,626	$ 2,085,522

Net Income (Loss) and Funds from Operations

Net loss for 2016 totaled $485.2 million ($2.29 per basic and diluted share) compared to a net loss of $1,142.9 million ($5.77 per basic and diluted share) for 2015. Funds from operations for 2016 totaled $276.3 million ($1.30 per basic and diluted share) as compared to $516.4 million ($2.61 per basic and diluted share) for 2015. The components of the change in net income (loss) and funds from operations from 2015 to 2016 are detailed in the following table:

($ thousands)	Years Ended December 31 Net income (loss)	Funds from operations
2015	**$ (1,142,880)**	$ 516,417
Increase (decrease) in revenues		
Revenue, net of royalties	**(278,020)**	(278,020)
(Increase) decrease in expenses		
Operating	**79,482**	79,482
Transportation	**24,870**	24,870
Blending	**18,208**	18,208
General and administrative	**8,540**	8,540
Exploration and evaluation	**2,799**	–
Depletion and depreciation	**153,549**	–
Impairment	**615,378**	–
Share-based compensation	**10,691**	–
Financing and interest	**(2,539)**	(281)
Financial derivatives	**(185,936)**	(100,616)
Foreign exchange	**253,391**	(2,044)
Other(1)(2)	**28,826**	(7,254)
Current income tax	**16,949**	16,949
Deferred income tax	**(88,492)**	–
2016	**$ (485,184)**	$ 276,251

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

(2) For funds from operations, "other" includes the cash component of other income/expense and payments on onerous contracts.

Dividends

In response to the prolonged low price commodity environment and in an effort to preserve liquidity, we suspended our monthly dividend beginning in September of 2015. During 2015, we declared monthly dividends of $0.10 per common share from January to August totaling $0.80 per common share. In total, $96.6 million of the dividends were paid in cash and $57.3 million were settled by issuing 4,707,914 common shares under our dividend reinvestment plan during 2015. No dividends have been declared or paid subsequent to 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 $75.5 million foreign currency translation loss for 2016 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar at December 31, 2016 (1.3427 CAD/USD) as compared to December 31, 2015 (1.3840 CAD/USD).

Capital Expenditures

Capital expenditures for the years ended December 31, 2016 and 2015 are summarized as follows:

	Years Ended December 31					
	2016			2015		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 4,053**	**$ 6,098**	**$ 10,151**	$ 4,704	$ 276	$ 4,980
Seismic	**638**	**–**	**638**	300	–	300
Drilling, completion and equipping	**13,618**	**178,412**	**192,030**	45,937	420,559	466,496
Facilities	**7,564**	**14,400**	**21,964**	20,309	28,954	49,263
Total exploration and development	**$ 25,873**	**$ 198,910**	**$ 224,783**	$ 71,250	$ 449,789	$ 521,039
Total acquisitions, net of proceeds from divestitures	**(8,883)**	**(54,237)**	**(63,120)**	1,641	7	1,648
Total oil and natural gas expenditures	**$ 16,990**	**$ 144,673**	**$ 161,663**	$ 72,891	$ 449,796	$ 522,687
Wells drilled (net)	**4.0**	**36.9**	**40.9**	31.4	50.2	81.6

2016 capital expenditures totaled $224.8 million as compared to $521.0 million in 2015. Capital spending has been focused on our Eagle Ford assets which accounted for 88% of 2016 capital expenditures. In the U.S., capital spending decreased to $198.9 million in 2016 from $449.8 million in 2015 due to lower activity levels associated with lower commodity prices combined with significant cost savings achieved on our Eagle Ford capital program. We drilled 127 (36.9 net) wells in the Eagle Ford in 2016 compared to 188 (50.2 net) wells in 2015. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$4.5 million per well as compared to US$6.2 million per well in 2015 representing a 28% decrease year over year. In Canada, all operated heavy oil drilling was deferred due to the low price environment. For 2016 we drilled 15 (4.0 net) wells and spent $25.9 million compared to 2015 when we drilled 40 (31.4 net) wells and spent $71.3 million.

On July 27, 2016, the Company disposed of its operated interest in certain Eagle Ford properties for proceeds of $54.2 million, which consisted of $11.8 million of oil and gas properties and $2.3 million of exploration and evaluation assets, resulting in a gain on disposition of $40.1 million.

During 2016, the Company disposed of certain non-core assets in Canada for total proceeds of $9.0 million. The divestitures consisted of $5.1 million of oil and gas properties and $0.1 million of exploration and evaluation assets, resulting in a gain on dispositions of $3.8 million.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

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

We regularly review our exposure to counterparties to ensure they have the financial capacity to honor outstanding obligations to us in the normal course of business and, in certain circumstances, we will seek enhanced credit protection from these counterparties.

The current commodity price environment has reduced our internally generated funds from operations. As a result, we have taken several steps to protect our liquidity, which included reducing our 2016 capital program by approximately 40% from our initial plans and working with our lending syndicate to secure our bank credit facilities. We also shut-in low or negative margin production for part of 2016 and sold non-core assets during the year for proceeds of $63.6 million that were applied to our credit facilities. On December 12, 2016, we closed an equity financing and issued 21,907,500 common shares for aggregate gross proceeds of approximately $115 million. The net proceeds, after issuance costs, of approximately $109.9 million were applied to our credit facilities and subsequently used to fund the acquisition of assets in the Peace River area of Alberta for approximately $65 million on January 20, 2017.

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

At December 31, 2016, net debt was $1,773.5 million, as compared to $2,049.9 million at December 31, 2015, representing a decrease of $276.4 million. Funds from operations for 2016 exceeded capital spending by $51.5 million which reduced net debt. We also applied the proceeds of $63.6 million from non-core asset sales along with the $109.9 million from the equity financing late in 2016 to reduce our debt levels. The strengthening Canadian dollar against the U.S. dollar at December 31, 2016 compared to December 31, 2015 reduced the carrying value of our U.S. dollar denominated long-term notes and bank loans further reducing our net debt.

Bank Loan

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

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

The weighted average interest rate on the credit facilities for 2016 was 3.5%, as compared to 4.2% for 2015.

Covenants

On March 31, 2016, we amended our credit facilities and restructured the financial covenants applicable to the Revolving Facilities. The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at December 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	Position as at December 31, 2016	December 31, 2016 to March 31, 2018	June 30, 2018 to September 30, 2018	December 31, 2018	Thereafter
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	0.6:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	3.6:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2016, our Senior Secured Debt totaled $204 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2016 was $373 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2016 were $104 million.

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

Long-Term Notes

We have five series of long-term notes outstanding that total $1.58 billion as at December 31, 2016. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2016, the fixed charge coverage ratio was 3.6:1.00.

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

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

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

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

Financial Instruments

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

A summary of the risk management contracts in place as at December 31, 2016 and the accounting treatment thereof is disclosed in note 18 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. In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and completed an equity financing for approximately $115 million to fund the acquisition. The financing closed on December 12, 2016 and we issued 21,907,500 common shares for total proceeds of $109.9 million (net of issue costs). We also issued 958,516 common shares pursuant to our share-based compensation program during the year. As at March 1, 2017, we had 234,204,090 common shares and no preferred shares issued and outstanding.

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

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 112,973**	$ 112,973	$ –	$ –	$ –
Bank loan(1)(2)	**191,286**	–	191,286	–	–
Long-term notes(2)	**1,584,158**	–	–	747,078	837,080
Interest on long-term notes(3)	**404,769**	64,325	128,650	127,847	83,947
Operating leases	**38,982**	8,164	15,511	12,679	2,628
Processing agreements	**48,833**	9,631	11,130	9,043	19,029
Transportation agreements	**59,172**	10,998	23,670	22,674	1,830
Total	**$ 2,440,173**	$ 206,091	$370,247	$ 919,321	$ 944,514

(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.

(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

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

SELECTED ANNUAL INFORMATION

($ thousands, except per common share amounts)	2016	2015	2014
Revenues, net of royalties	$ 601,979	$ 879,999	$ 1,529,897
Net income (loss)	$ (485,184)	$ (1,142,880)	$ (136,998)
Per common share – basic	$ (2.29)	$ (5.77)	$ (0.92)
Per common share – diluted	$ (2.29)	$ (5.77)	$ (0.92)
Total assets	$ 4,594,085	$ 5,488,498	$ 6,230,596
Total bank loan and long-term notes	$ 1,754,070	$ 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)	$ 30.29	$ 35.40	$ 66.54
Total production (boe/d)	69,509	84,648	78,395

QUARTERLY FINANCIAL INFORMATION

	2016				2015			
($ thousands, except per common share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	233,116	197,648	195,733	153,598	229,361	265,876	342,802	283,384
Net income (loss)	(359,424)	(39,430)	(86,937)	607	(419,175)	(519,247)	(27,096)	(177,362)
Per common share – basic	(1.66)	(0.19)	(0.41)	–	(1.99)	(2.50)	(0.13)	(1.05)
Per common share – diluted	(1.66)	(0.19)	(0.41)	–	(1.99)	(2.50)	(0.13)	(1.05)
Funds from operations	77,239	72,106	81,261	45,645	93,095	105,052	158,049	160,221
Per common share – basic	0.36	0.34	0.39	0.22	0.44	0.51	0.77	0.95
Per common share – diluted	0.36	0.34	0.39	0.22	0.44	0.51	0.77	0.95
Exploration and development	68,029	39,579	35,490	81,685	140,796	126,804	106,010	147,429
Canada	12,151	6,120	2,747	4,855	8,804	33,484	7,690	21,272
U.S.	55,878	33,459	32,743	76,830	131,992	93,320	98,320	126,157
Acquisitions, net of divestitures	(322)	(62,752)	(37)	(9)	(574)	(498)	1,170	1,550
Net debt	1,773,541	1,864,022	1,942,538	1,981,343	2,049,905	1,949,736	1,822,511	2,455,995
Total assets	4,594,085	4,995,876	5,089,280	5,197,913	5,488,498	5,893,759	6,189,417	6,419,922
Common shares outstanding	233,449	211,542	210,715	210,689	210,583	210,225	206,193	169,001
Daily production								
Total production (boe/d)	65,136	67,167	70,031	75,776	81,110	82,170	84,812	90,710
Canada (boe/d)	31,704	33,615	31,722	34,709	40,826	43,229	45,264	49,634
U.S. (boe/d)	33,432	33,552	38,309	41,067	40,284	38,941	39,548	41,076
Benchmark prices								
WTI oil (US$/bbl)	49.29	44.94	45.60	33.45	42.18	46.43	57.94	48.64
WCS heavy (US$/bbl)	34.97	31.44	32.29	19.22	27.69	33.13	46.35	33.91
CAD/USD avg exchange rate	1.3339	1.3051	1.2885	1.3748	1.3353	1.3094	1.2294	1.2308
AECO gas ($/mcf)	2.81	2.20	1.25	2.11	2.65	2.70	2.67	2.95
NYMEX gas (US$/mmbtu)	2.98	2.81	1.95	2.09	2.27	2.77	2.64	2.98
Sales price ($/boe)	38.16	31.73	30.52	21.93	30.03	34.59	43.34	33.54
Royalties ($/boe)	9.28	7.37	6.65	5.02	6.61	7.61	10.10	6.95
Operating expense ($/boe)	9.96	9.07	8.67	10.11	9.76	10.25	10.64	10.75
Transportation expense ($/boe)	1.30	1.38	0.81	0.98	1.45	1.52	1.94	1.95
Operating netback ($/boe)	17.62	13.91	14.39	5.82	12.21	15.21	20.66	13.89
Financial derivatives gain ($/boe)	1.62	3.04	3.74	6.47	4.09	3.33	5.19	12.48
Operating netback after financial derivatives ($/boe)	19.24	16.95	18.13	12.29	16.30	18.54	25.85	26.37

Our operating results over the last eight quarters have been consistent with our expectations and have varied primarily in response to the changes in oil prices. Oil prices have been at multi-year lows in the last eight quarters as the WTI oil price averaged less than US$50/bbl for seven out of the last eight quarters with a low of US$33.45/bbl in Q1/2016. Production has declined since Q1/2015 with reduced capital spending over the last two years in response to the lower price environment. Production in Canada has declined more than our U.S. production as there have been no operated heavy oil wells drilled in Canada since Q3/2015. Capital expenditures have been directed primarily to our Eagle Ford assets over the last two years as these assets generate our highest netbacks and highest rates of return. FFO has decreased coinciding with the declining oil price and lower production. Despite the lower FFO, our net debt has decreased to $1.8 billion in Q4/2016 down from $2.5 billion in Q1/2015. Over the last two years we have completed two equity financings raising gross proceeds of $633 million in Q2/2015 and $115 million in Q4/2016. In addition, we disposed of our operated assets in the Eagle Ford for proceeds of $54 million in Q3/2016 and sold other non-core assets for proceeds of approximately $9 million. Total assets have decreased from $6.4 billion in Q1/2015 to $4.6 billion in Q4/2016. Over the last two years the Company has recorded total impairment losses of $1.5 billion primarily related to the reduction in oil prices. These impairments have reduced the carrying value of our assets.

FOURTH QUARTER OF 2016

Our operating results for the fourth quarter were consistent with our expectations. Production averaged 65,136 boe/d in Q4/2016, as compared to 67,167 boe/d in Q3/2016 which resulted in annual average production of 69,509 boe/d, in line with our production guidance range of 69,000 to 70,000 boe/d.

In the Eagle Ford, production was stable during the fourth quarter, averaging 33,432 boe/d as compared to 33,552 boe/d in Q3/2016. During the fourth quarter, drilling activity increased as we averaged 3-4 drilling rigs and 1-2 completion crew on our lands, with two additional rigs being added by the end of the quarter. In Canada, production averaged 31,704 boe/d as compared to 33,615 boe/d in Q3/2016. Canadian production has decreased as we continued to limit capital expenditures on our Canadian assets during the fourth quarter due to the low oil price.

Capital expenditures for exploration and development activities totaled $68.0 million in Q4/2016 and $224.8 million for full-year 2016, in line with our guidance range of $200-225 million. In the Eagle Ford, we participated in the drilling of 27 (7.4 net) wells and placed 39 (11.6 net) wells on stream during Q4/2016. We have continued to realize cost reduction with wells being drilled, completed and equipped for approximately US$4.5 million per well in Q4/2016, down 20% from approximately US$5.6 million per well in Q1/2016. In Canada, we participated in the drilling of 14 (2.98 net) non-operated vertical wells at Lindbergh during Q4/2016.

In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and also completed a $115 million equity financing to fund the acquisition. The equity financing closed on December 12, 2016 with 21.9 million shares issued for proceeds of $109.9 million (net of issue costs). The Peace River acquisition closed subsequent to year end on January 20, 2017.

We generated FFO of $77.2 million ($0.36 per share) in Q4/2016, compared to $72.1 million ($0.34 per share) in Q3/2016. The increase in FFO was primarily driven by a higher oil price which averaged US$49.29/bbl in Q4/2016 compared to US$44.94/bbl in Q3/2016. The oil price increased to more than US$50/bbl in December of 2016 after OPEC and non-OPEC countries announced their intentions to cut production levels on November 30, 2016. The higher oil prices increased oil and natural gas revenue for Q4/2016 by $33 million to $229 million, up from $196 million in Q3/2016. This was offset by higher royalties, higher operating expense and lower financial derivative gains which reduced FFO, contributing to the $5 million overall increase in FFO from Q3/2016.

Operating netback per boe increased to $17.62/boe in Q4/2016 compared to $13.91/boe in Q3/2016. The increase in netback per boe is directly attributable to higher oil prices which resulted in higher oil and gas revenues per boe of $38.16/boe in Q4/2016 compared to $31.73/boe in Q3/2016. The increased revenue per boe was slightly offset by higher royalty rates and higher operating costs per boe in Q4/2016 compared to Q3/2016. Royalty rates increased to 24.3% of revenue in Q4/2016 from 23.2% of revenue in Q3/2016 due to higher pricing and minor prior period adjustments. Operating expense averaged $9.96/boe in Q4/2016 up from $9.07/boe in Q3/2016. In Canada, operating expense increased to $13.10/boe in Q4/2016 from $12.32/boe in Q3/2016 with increased maintenance and the effect of fixed costs on lower production volumes. In the U.S., operating expense increased to $6.98/boe in Q4/2016 from $5.82/boe in Q3/2016 due to minor prior period adjustments and foreign exchange as the CAD/USD exchange rate increased.

We recorded a net loss in Q4/2016 of $359.4 million ($1.66 per share) compared to a net loss of $39.4 million ($0.19 per share) in Q3/2015. The net loss in the quarter is largely attributable to impairment charges of $396.6 million. In

Q4/2016, we recorded an impairment charge of $166.6 million on our exploration and evaluation assets in the Eagle Ford along with a $230.0 million impairment charge on our oil and gas properties in Peace River.

In Q4/2016, our FFO exceeded our capital expenditures by $9.2 million. This along with the proceeds from the equity financing contributed to our net debt decreasing by $90.5 million from Q3/2016. As at December 31, 2016 our net debt was $1.77 billion and we had approximately $580 million of undrawn credit capacity on our revolving credit facilities. We were also in compliance with all of our financial covenants as at December 31, 2016.

The following table provides select operating results for Q4/2016.

	Three Months Ended December 31					
	2016			2015		
($ thousands, except as noted)	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production						
Heavy oil (bbl/d)	22,982	–	22,982	31,733	–	31,733
Light oil and condensate (bbl/d)	1,281	18,882	20,163	1,600	23,330	24,930
NGL (bbl/d)	1,307	7,012	8,319	973	8,023	8,996
Natural gas (mcf/d)	36,804	45,228	82,032	39,122	53,586	92,708
Total production (boe/d)	31,704	33,432	65,136	40,826	40,284	81,110
Baytex Average Sales Prices						
Canadian heavy oil ($/bbl)[1]	$ 34.33	$ –	$ 34.33	$ 24.41	$ –	$ 24.41
Light oil and condensate ($/bbl)	55.16	60.45	60.12	47.84	50.33	50.17
NGL ($/bbl)	18.50	23.41	22.64	19.93	16.90	17.23
Natural gas ($/mcf)	2.78	4.28	3.61	2.36	3.05	2.76
Weighted average ($/boe)[2]	$ 31.10	$ 44.84	$ 38.16	$ 23.59	$ 36.56	$ 30.03
Operating netback ($/boe)						
Oil and natural gas revenues	$ 31.10	$ 44.84	$ 38.16	$ 23.59	$ 36.56	$ 30.03
Less:						
Royalties	4.82	13.52	9.28	2.72	10.56	6.61
Operating expenses	13.10	6.98	9.96	12.27	7.23	9.76
Transportation expenses	2.67	–	1.30	2.87	–	1.45
Operating netback	$ 10.51	$ 24.34	$ 17.62	$ 5.73	$ 18.77	$ 12.21
Financial derivatives gain	$ –	$ –	$ 1.62	$ –	$ –	$ 4.09
Operating netback after financial derivatives	$ 10.51	$ 24.34	$ 19.24	$ 5.73	$ 18.77	$ 16.30
Capital Expenditures						
Exploration and development	$ 12,151	$ 55,878	$ 68,029	$ 8,804	$ 131,992	$ 140,796
Acquisitions, net of divestitures	$ (218)	$ (104)	$ (322)	$ (593)	$ 19	$ (574)

(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.

2017 GUIDANCE

In Canada, we have initiated an active first quarter drilling program in 2017 after limited activity over the past two years. In the Eagle Ford, we expect to maintain a consistent pace of development on our lands throughout 2017. We have designed our 2017 budget to be flexible should we continue to experience a volatile commodity price environment.

Our 2017 capital budget currently reflects a range of $300 to $350 million, which is designed to generate average annual production of 66,000 to 70,000 boe/d. For the full-year, approximately 70% of our planned capital expenditures will be directed to our Eagle Ford operations. The balance of the spending will be in Canada, largely toward our heavy oil assets at Peace River and Lloydminster. Our 2017 capital budget will be heavily weighted to drilling and completion activities (approximately 89%) with the balance for facilities (approximately 10%) and land and seismic (approximately 1%).

In the Eagle Ford, we expect to have four to five drilling rigs and two completion crews working on our lands, up from two to three rigs in the fourth quarter of 2016. At this pace of development, we expect to bring approximately 34 net wells on production in 2017. Our costs in the Eagle Ford continue to decrease with wells now being drilled, completed and equipped for approximately US$4.5 million.

In Canada, after two years of reduced activity and declining production, we are planning an active drilling program designed to stabilize production and ultimately, to position for growth. At Peace River, our capital budget includes drilling 11 net multi-lateral horizontal wells and 8 net stratigraphic wells. At Lloydminster, we plan to drill 52 net wells, of which approximately 55% will be horizontal wells. At Pembina, we expect to drill 2 net natural gas wells. Based on the mid-point of our 2017 annual average production guidance range of 68,000 boe/d, our production is expected to be equally split between Canada and the Eagle Ford. Our 2017 guidance includes an annual contribution of approximately 3,000 boe/d from our recently completed heavy oil acquisition at Peace River. Our production mix is forecast to be approximately 78% liquids (35% heavy oil, 31% light oil and condensate and 12% natural gas liquids) and 22% natural gas, based on a 6:1 natural gas-to-oil equivalency. Similar to 2016, we are targeting our 2017 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings and will remain flexible.

2017 Guidance

Exploration and development capital	$300-$350 million
Production	66,000 to 70,000 boe/d
Expenses:	
Royalty rate	approximately 23%
Operating	$11.00-$12.00/boe
Transportation	$1.10-$1.30/boe
General and administrative	approximately $50 million or $2.00/boe
Interest	approximately $100 million or $4.00/boe

OFF BALANCE SHEET TRANSACTIONS

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

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Accordingly, actual results can differ from those estimates. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, expenses, and disclosure of contingencies are discussed below.

Oil and Gas Activities

Reserves estimates can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion, asset retirement obligations, asset impairments and business combinations. The estimation of reserves is a complex process requiring significant judgment. The Company's reserves are estimated annually by independent reserves evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered (total proved plus probable reserves) or a 10 percent or greater statistical probability of being recovered (total possible reserves). Changes to estimates such as forward price estimates, production costs, recovery rates and, accordingly, economic status of reserves may have a material impact on the consolidated financial statements.

The Company's capital assets are aggregated into cash-generating units based on management's judgment of their ability to generate largely independent cash flows. The cash-generating units are used to assess impairment and, accordingly, can directly impact the recoverability of the assets therein. Impairment of assets and groups of assets are calculated based on the higher of value-in-use calculations and fair value less cost to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, royalty rates, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. Management applies judgment when it assesses internal and external factors to determine if indicators of impairment or indicators of impairment reversal exist.

The determination of technical feasibility and commercial viability of exploration and evaluation assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment.

Depletion and Depreciation

The amounts recorded for depletion of oil and gas properties are based on a unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. See "Oil and Gas Activities" above for discussion of estimates and judgments involved in reserve estimation.

Amounts recorded for depreciation are based on the estimated useful lives of depreciable assets which are reviewed by management at each reporting date.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value of assets and liabilities acquired often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net income (loss) can be affected as a result of changes in future depletion, depreciation, asset impairment or goodwill impairment.

Joint Control

Judgment is required to determine when the Company has joint control over a joint operation, which requires an assessment of the capital and operating activities of the projects undertaken with partners and when decisions in relation to those activities require unanimous consent.

Fair Value of Financial Instruments

Fair values of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs. These estimates may vary from the actual prices achieved upon settlement of the financial instruments.

Share-based Compensation

Compensation expense related to awards granted under the Company's Share Award Incentive Plan is dependent on estimated fair values, forfeiture rates and, for performance awards, a payout multiplier based on past performance. Compensation expense may fluctuate due to changes in management's estimates.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and the discount and inflation rates. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Legal

The Company is engaged in litigation and claims arising in the normal course of operations where the actual outcome may vary from the amount recognized in the consolidated financial statements. None of these claims are expected to materially affect the Company's financial position or reported results of operations.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and differing interpretations require management judgment. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. As such, income taxes are subject to measurement uncertainty.

We employ individuals skilled in making such estimates and ensure 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.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Revenue from Contracts with Customers

In April 2016, the International Accounting Standards Board (the "IASB") issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. 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 standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. We will adopt IFRS 15 on January 1, 2018 and are currently in the process of creating a plan to identify and review our various revenue streams and underlying contracts and assessing the impact on our consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The new standard replaces 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. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. We currently do not apply hedge accounting to our derivative contracts nor do we intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. We will adopt IFRS 9 on January 1, 2018 and are currently evaluating its impact on our consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. We will adopt IFRS 16 on January 1, 2019 and are currently evaluating the impact of the standard on the consolidated financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2016, an evaluation was conducted of the effectiveness of our "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 ("NI 52-109")) under the supervision of and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit 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 our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our 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.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2016. The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, as reflected in their report for 2016. No changes were made to our internal control over financial reporting during the year ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial results. Listed below is a description of these risk and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2016 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. If crude oil and natural gas prices decline or fail to increase from their current levels it could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

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 by us 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 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.

Decreases to or a prolonged period of low 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, 2016 are estimated using forecast prices and costs. These prices are above current market prices for crude oil and natural gas. 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 Canadian GAAP. 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 our long-term 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 US$575 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. In addition, we are required to repay the long-term notes on maturity. There is 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, investor interest in the energy industry in general, 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 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 and development 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. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such operation.

Variations in Interest 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.

Variations in Foreign Exchange Rates

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 our Revolving Facilities and a large portion of our long-term notes are denominated in U.S. dollars and the interest and principal 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.

Risk Management

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 risk management 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 due to the volatile commodity environment.

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 we believe that we 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 our business, financial condition, results of operations and prospects.

Climate Change Regulation

Both Canada and the United States are signatories to the United Nations Framework Convention on Climate Change (the “UNFCCC”) and are participants in the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas (“GHG”) emissions). Both governments agreed to an economy-wide target to reduce GHG emissions by 17% from 2005 levels. Both governments also signed the Paris Agreement in December of 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius. Additionally, Canada pledged to reduce GHG emissions by 30% by 2030 from 2005 levels and the United States pledged to reduce GHG emissions by 26% to 28% by 2025 from 2005 levels.

The United States has not yet announced or enacted any mechanisms or legislation to implement the Paris Agreement. The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at $10/tonne rising by $10/tonne a year to $50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the Provinces and territories and would only be implemented in those Provinces and territories that do not have their own carbon tax.

The Province of Alberta announced and implemented a broad range of plans targeting GHG emissions, that include: a carbon levy of $20/tonne that became effective January 1, 2017 that will increase to $30/tonne in 2018; a cap on GHG emissions from the oil sands of 100 mega tonnes per year; and a plan to introduce regulations that will reduce methane emissions from oil and gas operations by 45% by 2025. The Province of Saskatchewan has set forth similar legislation that is not yet in force for facilities that emit more than 50,000 tonnes of GHGs. At present, we do not operate any facilities in Alberta or Saskatchewan that exceed these thresholds. We expect a minimal increase in operating costs through internal trucking and supplier rate increases as a result of the implementation of the carbon levy for our Alberta properties.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the percentage of our net exposure to WTI, the WCS differential and natural gas that is hedged for 2017; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; our expectation regarding the payment of cash income taxes prior to 2020; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; our belief that the amended credit facilities provide increased financial flexibility; the existence, operation and strategy of our risk management program; our capital budget for 2017; our annual average production rate for 2017; the breakdown of our 2017 capital budget by geographic area and expenditure type; our plan for developing our properties in 2017, including the number of rigs and completion crews in the Eagle Ford, the number of wells to be brought on production in the Eagle Ford, the cost to drill, complete and equip a well in the Eagle Ford, the number and type of wells to be drilled at Peace River, Lloydminster and Pembina; the geographic breakdown of our 2017 annual production and the production expected from our recently completed heavy oil acquisition at Peace River; our production mix for 2017; our target of funding our capital expenditures with funds from operations to minimize additional bank borrowings; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2017; and the effect that Alberta's carbon tax will have on our operating costs. 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; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; we may lose access to our information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2016, 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2016, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2016.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Baytex Energy Corp. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

James L. Bowzer
Chief Executive Officer
Baytex Energy Corp.

Rodney D. Gray
Chief Financial Officer
Baytex Energy Corp.

March 6, 2017

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors of Baytex Energy Corp.

We have audited the accompanying consolidated financial statements of Baytex Energy Corp., which comprise the consolidated statements of financial position as at December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Baytex Energy Corp. as at December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Comparative Information

Without modifying our opinion, we draw attention to Note 13 to the consolidated financial statements which indicates that the comparative information presented as at and for the year ended December 31, 2015, has been adjusted and that an opening statement of financial position as at January 1, 2015 is not presented.

The consolidated financial statements of Baytex Energy Corp. as at and for the year ended December 31, 2015 excluding the adjustment described in Note 13 to the consolidated financial statements were audited by another auditor who expressed an unmodified opinion on those financial statements on March 2, 2016.

As part of our audit of the consolidated financial statements as at and for the year ended December 31, 2016, we audited the adjustment described in Note 13 to the consolidated financial statements that was applied to adjust the comparative information presented as at and for the year ended December 31, 2015, and the opening statement of financial position as at January 1, 2015 (not presented herein). In our opinion, the adjustment is appropriate and has been properly applied.

We were not engaged to audit, review, or apply any procedures to the December 31, 2015, consolidated financial statements or the January 1, 2015, consolidated statement of financial position, other than with respect to the adjustment described in Note 13 to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Baytex Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 6, 2017 expressed an unmodified (unqualified) opinion on the effectiveness of Baytex Energy Corp.'s internal control over financial reporting.

KPMG LLP

Chartered Professional Accountants

March 6, 2017
Calgary, Canada

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Shareholders of Baytex Energy Corp.

We have audited Baytex Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Baytex Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Baytex Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statement of financial position of Baytex Energy Corp. as of December 31, 2016, and the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the year ended December 31, 2016, and our report dated March 6, 2017 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Professional Accountants

March 6, 2017
Calgary, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Baytex Energy Corp.

We have audited, before the effects of the adjustments to retrospectively apply the change in accounting discussed in Note 13 to the consolidated financial statements, the accompanying consolidated financial statements of Baytex Energy Corp. and subsidiaries (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2015, and the consolidated statement of loss and comprehensive loss, consolidated statement of changes in equity, and consolidated statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information (the 2015 consolidated financial statements before the effects of the adjustments discussed in Note 13 to the consolidated financial statements are not presented herein).

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements, before the effects of the adjustments to retrospectively apply the change in accounting discussed in Note 13 to the consolidated financial statements, present fairly, in all material respects, the financial position of Baytex Energy Corp. and subsidiaries as at December 31, 2015, and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Deloitte LLP

Chartered Professional Accountants

March 2, 2016
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	December 31, 2016	December 31, 2015
(thousands of Canadian dollars)		
ASSETS		
Current assets		
Cash	$ 2,705	$ 247
Trade and other receivables (note 18)	112,171	98,093
Financial derivatives (note 18)	2,219	106,573
	117,095	204,913
Non-current assets		
Financial derivatives (note 18)	–	4,417
Exploration and evaluation assets (note 6)	308,462	578,969
Oil and gas properties (note 7)	4,152,169	4,674,175
Other plant and equipment (note 8)	16,359	26,024
	$ 4,594,085	$ 5,488,498
LIABILITIES		
Current liabilities		
Trade and other payables (note 18)	$ 112,973	$ 267,838
Financial derivatives (note 18)	28,532	–
Onerous contracts (note 19)	9,504	–
	151,009	267,838
Non-current liabilities		
Bank loan (note 9)	187,954	252,172
Long-term notes (note 10)	1,566,116	1,602,757
Asset retirement obligations (note 11)	331,517	296,002
Deferred income tax liability (note 15)	375,695	655,255
Financial derivatives (note 18)	2,833	–
	2,615,124	3,074,024
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 12)	4,422,661	4,296,831
Contributed surplus (note 13)	21,405	22,045
Accumulated other comprehensive income	629,863	705,382
Deficit (note 13)	(3,094,968)	(2,609,784)
	1,978,961	2,414,474
	$ 4,594,085	$ 5,488,498

Commitments and contingencies (note 20)

Subsequent event (note 23)

See accompanying notes to the consolidated financial statements.

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

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

Years Ended December 31	2016	2015
(thousands of Canadian dollars, except per common share amounts)		
Revenue, net of royalties		
Petroleum and natural gas sales	$ 780,095	$ 1,121,424
Royalties	(178,116)	(241,425)
	601,979	879,999
Expenses		
Operating	240,705	320,187
Transportation	28,257	53,127
Blending	9,622	27,830
General and administrative	50,866	59,406
Exploration and evaluation (note 6)	5,976	8,775
Depletion and depreciation (notes 7 and 8)	508,309	661,858
Impairment (notes 6 and 7)	423,176	1,038,554
Share-based compensation (note 13)	13,882	24,573
Financing and interest (note 16)	114,199	111,660
Financial derivatives loss (gain) (note 18)	43,207	(142,729)
Foreign exchange (gain) loss (note 17)	(42,678)	210,713
Disposition of oil and gas properties (gain) loss (note 7)	(43,907)	1,519
Other expense (income)	8,152	(8,448)
	1,359,766	2,367,025
Net income (loss) before income taxes	(757,787)	(1,487,026)
Income tax (recovery) expense (note 15)		
Current income tax (recovery) expense	(8,042)	8,907
Deferred income tax (recovery)	(264,561)	(353,053)
	(272,603)	(344,146)
Net income (loss) attributable to shareholders	$ (485,184)	$(1,142,880)
Other comprehensive income (loss)		
Foreign currency translation adjustment	(75,519)	505,807
Comprehensive income (loss)	$ (560,703)	$ (637,073)
Net income (loss) per common share (note 14)		
Basic	$ (2.29)	$ (5.77)
Diluted	$ (2.29)	$ (5.77)
Weighted average common shares (note 14)		
Basic	212,298	198,207
Diluted	212,298	198,207

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	**Total equity**
(thousands of Canadian dollars)					
Balance at December 31, 2014 (note 13)	$ 3,580,825	$ 39,308	$ 199,575	$ (1,312,931)	**$ 2,506,777**
Dividends to shareholders (note 12)	–	–	–	(153,973)	**(153,973)**
Vesting of share awards (note 12)	41,836	(41,836)	–	–	**–**
Share-based compensation (note 13)	–	24,573	–	–	**24,573**
Issued for cash (note 12)	632,494	–	–	–	**632,494**
Issuance costs, net of tax (note 12)	(19,301)	–	–	–	**(19,301)**
Issued pursuant to dividend reinvestment plan (note 12)	60,977	–	–	–	**60,977**
Comprehensive income (loss) for the year	–	–	505,807	(1,142,880)	**(637,073)**
Balance at December 31, 2015 (note 13)	$ 4,296,831	$ 22,045	$ 705,382	$ (2,609,784)	**$ 2,414,474**
Vesting of share awards (note 12)	14,522	(14,522)	–	–	**–**
Share-based compensation (note 13)	–	13,882	–	–	**13,882**
Issued for cash (note 12)	115,014	–	–	–	**115,014**
Issuance costs, net of tax (note 12)	(3,706)	–	–	–	**(3,706)**
Comprehensive income (loss) for the year	–	–	(75,519)	(485,184)	**(560,703)**
Balance at December 31, 2016	$ 4,422,661	$ 21,405	$ 629,863	$ (3,094,968)	**$ 1,978,961**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31	2016	2015
(thousands of Canadian dollars)		
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income (loss) for the year	$ (485,184)	$(1,142,880)
Adjustments for:		
Share-based compensation (note 13)	13,882	24,573
Unrealized foreign exchange (gain) loss (note 17)	(41,436)	213,999
Exploration and evaluation (note 6)	5,976	8,775
Depletion and depreciation	508,309	661,858
Impairment (notes 6 and 7)	423,176	1,038,554
Non-cash financing and accretion (note 16)	10,514	8,256
Loss on onerous contracts (note 19)	10,116	–
Unrealized financial derivatives loss (note 18)	140,136	54,816
Disposition of oil and gas properties (gain) loss (note 7)	(43,907)	1,519
Deferred income tax (recovery)	(264,561)	(353,053)
Payments on onerous contracts (note 19)	(770)	–
Change in non-cash working capital (note 19)	(23,270)	43,891
Asset retirement obligations settled (note 11)	(5,616)	(10,888)
	247,365	549,420
Financing activities		
Payment of dividends	–	(109,806)
Decrease in bank loan	(60,910)	(439,465)
Tenders of long-term notes	–	(10,372)
Issuance of common shares, net of issuance costs (note 12)	109,939	606,095
	49,029	46,452
Investing activities		
Additions to exploration and evaluation assets (note 6)	(4,716)	(5,642)
Additions to oil and gas properties (note 7)	(220,067)	(515,397)
Property acquisitions	(117)	(2,070)
Proceeds from disposition of oil and gas properties (note 7)	63,237	423
Current income tax paid on dispositions	–	(8,181)
Dispositions to other plant and equipment, net of additions (note 8)	5,129	4,107
Change in non-cash working capital (note 19)	(135,743)	(70,968)
	(292,277)	(597,728)
Impact of foreign currency translation on cash balances	(1,659)	961
Change in cash	2,458	(895)
Cash, beginning of year	247	1,142
Cash, end of year	$ 2,705	$ 247
Supplementary information		
Interest paid	$ 104,183	$ 100,257
Income taxes paid	$ 5,332	$ 12,064

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2016 AND 2015

(all tabular amounts in thousands of Canadian dollars, except per common share amounts)

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The significant accounting policies set out below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 6, 2017.

The consolidated financial statements have been prepared on the historical cost basis, with some exceptions as noted in the accounting policies set out below. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated. Prior period financial statement amounts have been reclassified to conform with current period presentation and the adjustments to share-based compensation (see note 13).

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Accordingly, actual results can differ from those estimates. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, expenses, and disclosure of contingencies are discussed below.

Oil and Gas Activities

Reserves estimates can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion, asset retirement obligations, asset impairments and business combinations. The estimation of reserves is a complex process requiring significant judgment. The Company's reserves are estimated annually by independent reserves evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered (total proved plus probable reserves) or a 10 percent or greater statistical probability of being recovered (total possible reserves). Changes to estimates such as forward price estimates, production costs, recovery rates and, accordingly, economic status of reserves may have a material impact on the consolidated financial statements.

The Company's capital assets are aggregated into cash-generating units based on management's judgment of their ability to generate largely independent cash flows. The cash-generating units are used to assess impairment and, accordingly, can directly impact the recoverability of the assets therein. Impairment of assets and groups of assets are calculated based on the higher of value-in-use calculations and fair value less cost to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, royalty rates, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. Management applies judgment when it assesses internal and external factors to determine if indicators of impairment or indicators of impairment reversal exist.

The determination of technical feasibility and commercial viability of exploration and evaluation assets ("E&E") for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment.

Depletion and Depreciation

The amounts recorded for depletion of oil and gas properties are based on a unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. See "Oil and Gas Activities" above for discussion of estimates and judgments involved in reserve estimation.

Amounts recorded for depreciation are based on the estimated useful lives of depreciable assets which are reviewed by management at each reporting date.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value of assets and liabilities acquired often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net income (loss) can be affected as a result of changes in future depletion, depreciation, asset impairment or goodwill impairment.

Joint Control

Judgment is required to determine when the Company has joint control over a joint operation, which requires an assessment of the capital and operating activities of the projects undertaken with partners and when decisions in relation to those activities require unanimous consent.

Fair Value of Financial Instruments

Fair values of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs and are described in note 18. These estimates may vary from the actual prices achieved upon settlement of the financial instruments.

Share-based Compensation

Compensation expense related to awards granted under the Company's Share Award Incentive Plan is dependent on estimated fair values, forfeiture rates and, for performance awards, a payout multiplier based on past performance. Compensation expense may fluctuate due to changes in management's estimates.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and the discount and inflation rates. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Legal

The Company is engaged in litigation and claims arising in the normal course of operations where the actual outcome may vary from the amount recognized in the consolidated financial statements. None of these claims are expected to materially affect the Company's financial position or reported results of operations.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and differing interpretations require management judgment. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. As such, income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Partnership. Intercompany balances, net income (loss) and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

A portion of the Company's exploration, development and production activities are conducted through jointly controlled operations. The financial statements reflect the Company's proportionate interest where the Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases. Joint control exists for contractual arrangements governing assets whereby the Company has less than 100 per cent working interest, all of the partners have control of the arrangement collectively, and spending on the project requires unanimous consent of all parties that collectively control the arrangement and share the associated risks.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities, are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the deficiency is credited to net income (loss) in the statements of income (loss) and comprehensive income (loss) in the period of acquisition. Associated transaction costs are expensed when incurred.

Exploration and Evaluation Assets, Oil and Gas Properties and Other Plant and Equipment

Pre-license Costs

Pre-license costs are costs incurred before the legal rights to explore a specific area have been obtained. These costs are expensed in the period in which they are incurred.

E&E Costs

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well program/project is complete and the results have been evaluated. Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing. E&E costs are capitalized until technical feasibility and commercial viability of extracting petroleum and natural gas resources is considered to be determined. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. All such costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract value from the asset. If the asset is determined not to be technically feasible or economically viable, an impairment is charged to net income (loss). Upon determination of technical feasibility and commercial viability, the E&E assets attributable to those reserves are tested for impairment on transfer to oil and gas properties.

Borrowing Costs and Other Capitalized Costs

Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset. A qualifying asset is an asset that requires a period of one year or greater to get ready for its intended use or sale. Baytex currently has no qualifying assets that would allow for borrowing costs to be capitalized to the asset and all borrowing costs are expensed as incurred.

Depletion and Depreciation

The net carrying value of oil and gas properties is depleted using the unit-of-production method based on estimated proved and probable reserves. Future development costs, which are the estimated costs necessary to bring those reserves into production, are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil.

The depreciation methods and estimated useful lives for other plant and equipment are as follows:

Classification	Method	Rate or period
Motor Vehicles	Diminishing balance	15%
Office Equipment	Diminishing balance	20%
Computer Hardware	Diminishing balance	30%
Furniture and Fixtures	Diminishing balance	10%
Leasehold Improvements	Straight-line over life of the lease	Various
Other Assets	Diminishing balance	Various

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively. Field inventory which is included in other plant and equipment is valued at the lower of cost, using the weighted average cost method, or net realizable value and is not depreciated.

Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net identifiable assets acquired, which is inherently imprecise as estimates and judgment are required in the determination of the fair value of assets and liabilities. Goodwill is assessed for impairment at least annually at year end, or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is recognized in net income (loss) and is not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal. Goodwill is not deductible for income tax purposes.

Impairment

Non-derivative financial assets

The Company assesses non-derivative financial assets at each reporting date to determine whether there is any objective evidence indicating that it is impaired. Objective evidence exists if one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset is measured as the difference between the amortized cost of the financial asset and its recoverable amount.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in net income (loss). An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in net income (loss).

Non-financial Assets

E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Company assesses other assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable.

Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets (the "cash-generating unit" or "CGU"). Goodwill acquired is allocated to CGUs expected to benefit from synergies of the related business combination.

The Company assesses its CGUs for impairment when indicators of impairment exist or at least annually for CGUs with goodwill. The Company compares the recoverable amount of the CGU to its carrying amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value-in-use. In assessing the recoverable amount, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis. Impairment is charged to net income (loss) in the period in which it occurs.

For all assets (other than goodwill), an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized for the asset in prior years and circumstances indicate the impairment no longer exists. Such reversal is recognized in net income (loss). Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Asset Retirement Obligations

The Company recognizes a liability for the future asset retirement costs associated with its oil and gas properties discounted using the risk free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted to expense over its useful life. The liability is accreted until the date of expected settlement of the retirement obligation and is recognized within financing costs in the statements of income (loss) and comprehensive income (loss). Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign transactions

Transactions completed in currencies other than the functional currency are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to Canadian dollars at the period-end exchange rate. Revenue and expenses are translated to Canadian dollars using the average exchange rate for the period. Both realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income (loss).

Foreign operations

As several of the Company's subsidiaries operate and transact primarily in countries other than Canada, they accordingly have functional currencies other than the Canadian dollar. The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Assets and liabilities of foreign operations are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. The resulting unrealized gains or losses are included in accumulated other comprehensive income (loss) in shareholders' equity and are reclassified to net income (loss) when there has been a disposal or partial disposal of the foreign operation.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the delivery point and collectability of the revenue is probable. Revenue from the production of petroleum and natural gas in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant agreements. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty with the right and intent to settle net are recorded on a net basis.

Transportation Expense

Costs paid by Baytex for the transportation of crude oil, natural gas, condensate and NGLs to the point of title transfer are recognized when transportation is provided. For the U.S. operations, Baytex does not have sufficient information to bifurcate these costs and therefore transportation expenses has been included as part of operating expense.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair value through profit or loss ("FVTPL"), loans and receivables, held-to-maturity investments, available-for-sale financial assets and other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets are measured at fair value and changes in fair value are recognized in net income (loss). Available-for-sale financial assets are measured at fair value with changes in fair value recorded in other comprehensive income (loss) until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest method. Cash and financial derivatives are classified at FVTPL. Trade and other receivables are classified as loans and receivables, which are measured at amortized cost. Trade and other payables, dividends payable to shareholders, bank loan and long-term notes are classified as other financial liabilities, which are measured at amortized cost.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The embedded derivatives are measured at FVTPL.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed immediately. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income (loss) over the term of the financial instrument. Debt issuance costs related to the restructuring of credit facilities are capitalized and amortized as financing costs over the term of the credit facilities.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. These instruments are classified as FVTPL. The Company does not use financial derivatives for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the statements of income (loss) and comprehensive income (loss) for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income (loss) when incurred.

The Company has accounted for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Income Taxes

Current and deferred income taxes are recognized in net income (loss), except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity. When current income tax or deferred income tax arises from the initial accounting for a business combination, the tax effect is included in the accounting for the business combination as goodwill.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period.

The Company follows the balance sheet asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

The Company has a full-value award plan (the “Share Award Incentive Plan”) pursuant to which restricted awards and performance awards (collectively, “share awards”) may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.8% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Under the Share Award Incentive Plan, common shares are issued as to one-sixth on the first anniversary date of the grant and as to one-sixth every six months thereafter (with the last issuance to occur 36 months following grant date (42 months for grants prior to 2016)). Expenses related to the Share Award Incentive Plan are determined based on the fair value of the share awards on the grant date. Both restricted and performance awards are expensed over the vesting period. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. 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 standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 15 will be applied by Baytex on January 1, 2018. The Company is currently in the process of creating a plan to identify and review its various revenue streams and underlying contracts and assessing the impact on the consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The new standard replaces 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. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company currently does not apply hedge accounting to its derivative contracts nor does it intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 9 will be applied by Baytex on January 1, 2018. The Company is currently evaluating its impact on the consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. IFRS 16 will be applied by Baytex on January 1, 2019. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

5. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 299,632**	$ 521,104	**$ 480,463**	$ 600,320	**$ –**	$ –	**$ 780,095**	$ 1,121,424
Royalties	**(37,720)**	(67,323)	**(140,396)**	(174,102)	**–**	–	**(178,116)**	(241,425)
	261,912	453,781	**340,067**	426,218	**–**	–	**601,979**	879,999
Expenses								
Operating	**142,242**	210,945	**98,463**	109,242	**–**	–	**240,705**	320,187
Transportation	**28,257**	53,127	**–**	–	**–**	–	**28,257**	53,127
Blending	**9,622**	27,830	**–**	–	**–**	–	**9,622**	27,830
General and administrative	**–**	–	**–**	–	**50,866**	59,406	**50,866**	59,406
Exploration and evaluation	**5,976**	8,775	**–**	–	**–**	–	**5,976**	8,775
Depletion and depreciation	**210,778**	279,744	**293,231**	377,847	**4,299**	4,267	**508,309**	661,858
Impairment	**256,559**	45,703	**166,617**	992,851	**–**		**423,176**	1,038,554
Share-based compensation (note 13)	**–**	–	**–**	–	**13,882**	24,573	**13,882**	24,573
Financing and interest	**–**	–	**–**	–	**114,199**	111,660	**114,199**	111,660
Financial derivatives (gain)	**–**	–	**–**	–	**43,207**	(142,729)	**43,207**	(142,729)
Foreign exchange loss	**–**	–	**–**	–	**(42,678)**	210,713	**(42,678)**	210,713
Disposition of oil and gas properties (gain) loss	**(3,883)**	1,769	**(40,024)**	(250)	**–**	–	**(43,907)**	1,519
Other expense (income)	**–**	–	**–**	–	**8,152**	(8,448)	**8,152**	(8,448)
	649,551	627,893	**518,287**	1,479,690	**191,927**	259,442	**1,359,766**	2,367,025
Net income (loss) before income taxes	**(387,639)**	(174,112)	**(178,220)**	(1,053,472)	**(191,927)**	(259,442)	**(757,787)**	(1,487,026)
Income tax (recovery) expense								
Current income tax (recovery) expense	**(6,577)**	6,577	**(1,156)**	1,946	**(309)**	384	**(8,042)**	8,907
Deferred income tax (recovery) expense	**(99,215)**	(39,191)	**(112,907)**	(324,940)	**(52,439)**	11,078	**(264,561)**	(353,053)
	(105,792)	(32,614)	**(114,063)**	(322,994)	**(52,748)**	11,462	**(272,603)**	(344,146)
Net income (loss)	**$(281,847)**	$(141,498)	**$ (64,157)**	$ (730,478)	**$(139,179)**	$(270,904)	**$ (485,184)**	$(1,142,880)
Total oil and natural gas capital expenditures[(1)]	**$ 16,990**	$ 72,891	**$ 144,673**	$ 449,796	**$ –**	$ –	**$ 161,663**	$ 522,687

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

As at	December 31, 2016	December 31, 2015
Canadian assets	**$ 1,625,546**	$ 2,059,903
U.S. assets	**2,955,965**	3,304,647
Corporate assets	**12,574**	123,948
Total consolidated assets	**$ 4,594,085**	$ 5,488,498

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2016	December 31, 2015
Balance, beginning of year	**$ 578,969**	$ 542,040
Capital expenditures	**4,716**	5,642
Property acquisitions, net of divestitures	**102**	1,813
Impairment	**(166,617)**	–
Exploration and evaluation expense	**(5,976)**	(8,775)
Transfer to oil and gas properties	**(85,069)**	(38,062)
Divestitures	**(2,455)**	(1,588)
Foreign currency translation	**(15,208)**	77,899
Balance, end of year	**$ 308,462**	$ 578,969

During the year ended December 31, 2016, the Company derecognized $166.6 million of exploration and evaluation assets in the U.S. CGU due to changes to the Company's development plan, which resulted in possible reserves being reclassified to contingent resources. In addition, the Company also transferred $85.1 million from exploration and evaluation assets to oil and gas properties upon establishment of proved and probable reserves in the U.S. CGU that were previously classified as possible reserves.

At December 31, 2016, there were no indicators of impairment for exploration and evaluation assets relating to CGUs in Canada.

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2014	**$6,431,760**	**$ (1,447,844)**	**$4,983,916**
Capital expenditures	515,397	–	515,397
Property acquisitions	551	–	551
Transferred from exploration and evaluation assets	38,062	–	38,062
Change in asset retirement obligations	10,722	–	10,722
Divestitures	(20,096)	19,449	(647)
Impairment	–	(755,613)	(755,613)
Foreign currency translation	607,885	(68,509)	539,376
Depletion	–	(657,589)	(657,589)
Balance, December 31, 2015	**$7,584,281**	**$ (2,910,106)**	**$4,674,175**
Capital expenditures	220,067	–	220,067
Property acquisitions	54	–	54
Transferred from exploration and evaluation assets	85,069	–	85,069
Change in asset retirement obligations	35,714	–	35,714
Divestitures	(59,874)	42,959	(16,915)
Impairment	–	(256,559)	(256,559)
Foreign currency translation	(101,274)	15,616	(85,658)
Depletion	–	(503,778)	(503,778)
Balance, December 31, 2016	**$7,764,037**	**$ (3,611,868)**	**$4,152,169**

For the year ended December 31, 2016, the Company recorded total impairment expense to oil and gas properties of $256.6 million (2015 – $755.6 million).

U.S. Assets

On July 27, 2016, the Company disposed of its operated interest in certain Eagle Ford properties for proceeds of $54.2 million, which consisted of $11.8 million of oil and gas properties and $2.3 million of exploration and evaluation assets, resulting in a gain on disposition of $40.1 million.

At December 31, 2016, the Company had no indicators of impairment in the U.S. CGU and as a result no impairment assessment was performed.

At December 31, 2015, indicators of impairment arose as a result of declining commodity prices. Impairment of $992.9 million ($741.3 million net of tax) was recorded in the U.S. CGU as a reduction to oil and gas properties of $709.9 million and the Company's remaining goodwill of $282.9 million. The recoverable amount for the U.S. CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2015. The recoverable amount of oil and gas properties of $3,222.0 million for the U.S. CGU was estimated based on their fair value less costs of disposal at December 31, 2015.

Canadian Assets

At September 30, 2016, the Company recorded a $26.6 million impairment expense in its Lloydminster CGU on assets that were reclassified from oil and gas assets to assets held for sale prior to their disposition in the fourth quarter of 2016. The carrying value of the assets transferred to assets held for sale exceeded the fair value (being the sales price) resulting in the impairment. During 2016, the Company disposed of certain non-core assets in Canada for total proceeds of $9.0 million, which consisted of $5.1 million of oil and gas properties and $0.1 million of exploration and evaluation assets, resulting in a gain on disposition of $3.8 million.

At December 31, 2016, indicators of impairment existed for the Peace River CGU as a result of downward technical revisions to reserves. Impairment of $230.0 million was recorded in the Peace River CGU. The recoverable amount for the Peace River CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2016. The recoverable amount of oil and gas properties of $550.2 million for the Peace River CGU was estimated based on their fair value less costs of disposal at December 31, 2016. For impairment assessments of oil and gas properties, the Company estimates the recoverable amount using a discounted cash flow model based on an independent reserve report approved by the Board of Directors on an annual basis and a range of pre-tax discount rates of 10% to 15%.

The recoverable amount of the Peace River CGU was calculated at December 31, 2016 using the following benchmark reference prices for the years 2017 to 2021 adjusted for commodity differentials specific to the Company:

	2017	2018	2019	2020	2021
WTI crude oil (US$/bbl)	55.00	65.00	70.00	71.40	72.83
NYMEX natural gas (US$/MMBtu)	3.50	3.50	3.50	4.00	4.08
Exchange rate (CAD/USD)	1.28	1.22	1.18	1.18	1.18

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2021 have been adjusted for inflation at an annual rate of 2.0%.

The fair value less costs of disposal values used to determine the recoverable amount of the Peace River CGU are classified as Level 3 fair value measures as they are based on the Company's estimate of key assumptions that are not based on observable market data.

The results of the impairment test are sensitive to changes in any of the key judgments, such as a revision in reserves, a change in forecast commodity prices, expected royalties, future development capital expenditures or expected future production costs, which could decrease or increase the recoverable amounts of assets and result in additional impairment or recovery of impairment. For the Peace River CGU, an increase in the discount rate of 1 percent would result in additional impairment of $26.4 million. A decrease in commodity prices of 5 percent would result in additional impairment of $59.9 million.

In November 2015, the Company completed a disposition of certain non-core assets in its Lloydminster CGU and recorded an impairment of $45.7 million.

8. OTHER PLANT AND EQUIPMENT

	Cost	Accumulated depreciation	Net book value
Balance, December 31, 2014	**$76,708**	**$(42,440)**	**$34,268**
Capital expenditures	3,577	–	3,577
Dispositions	(7,684)	–	(7,684)
Foreign currency translation	277	(147)	130
Depreciation	–	(4,267)	(4,267)
Balance, December 31, 2015	**72,878**	**(46,854)**	**26,024**
Capital expenditures	1,934	–	1,934
Dispositions, net of acquisitions	(7,063)	–	(7,063)
Foreign currency translation	(51)	46	(7)
Depreciation	–	(4,531)	(4,529)
Balance, December 31, 2016	**67,698**	**(51,339)**	**16,359**

9. BANK LOAN

	December 31, 2016	December 31, 2015
Bank loan – U.S. dollar denominated[(1)]	**$ 191,286**	$ 237,861
Bank loan – Canadian dollar denominated	**–**	18,888
Bank loan – principal	**191,286**	256,749
Unamortized debt issuance costs	**(3,332)**	(4,577)
Bank loan	**$ 187,954**	$ 252,172

(1) U.S. dollar denominated bank loan balance as at December 31, 2016 was US$142.5 million (US$171.9 million as December 31, 2015)

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

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

At December 31, 2016, Baytex had $12.6 million of outstanding letters of credit (December 31, 2015 – $12.4 million) under the Revolving Facilities.

At December 31, 2016, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants contained in the Revolving Facilities and Baytex's compliance therewith as at December 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	Position as at December 31, 2016	December 31, 2016 to March 31, 2018	June 30, 2018 to September 30, 2018	December 31, 2018	Thereafter
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	0.6:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	3.6:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2016, the Company's Senior Secured Debt totaled $204 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2016 was $373 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2016 were $104 million.

10. LONG-TERM NOTES

	December 31, 2016	December 31, 2015
7.5% notes (US$6,400 – principal) due April 1, 2020	$ 8,593	$ 8,858
6.75% notes (US$150,000 – principal) due February 17, 2021	201,405	207,600
5.125% notes (US$400,000 – principal) due June 1, 2021	537,080	553,600
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	300,000	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	537,080	553,600
Total long-term notes – principal	1,584,158	1,623,658
Unamortized debt issuance costs	(18,042)	(20,901)
Total long-term notes – net of unamortized debt issuance costs	$ 1,566,116	$ 1,602,757

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Revolving Facilities and long-term notes unless the Company maintains a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 9) to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2016, the fixed charge coverage ratio was 3.59:1.00.

11. ASSET RETIREMENT OBLIGATIONS

	December 31, 2016	December 31, 2015
Balance, beginning of year	**$ 296,002**	$ 286,032
Liabilities incurred	**5,642**	4,964
Liabilities settled	**(5,616)**	(10,888)
Liabilities acquired	**–**	593
Liabilities divested	**(10,590)**	(10,578)
Accretion	**6,174**	6,262
Change in estimate[1]	**20,402**	33,266
Changes in discount rates and inflation rates	**20,260**	(17,523)
Foreign currency translation	**(757)**	3,874
Balance, end of year	**$ 331,517**	$ 296,002

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

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the asset retirement obligations is $605.4 million (December 31, 2015 – $561.4 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2016 using an estimated annual inflation rate of 1.75% (December 31, 2015 – 1.50%) and discounted at a risk free rate of 2.25% (December 31, 2015 – 2.25%) is $331.5 million (December 31, 2015 – $296.0 million).

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2016, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meetings of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares (000s)	Amount
Balance, December 31, 2014	**168,107**	**$3,580,825**
Transfer from contributed surplus on vesting and conversion of share awards	1,092	41,836
Issued for cash	36,455	632,494
Issuance costs, net of tax	–	(19,301)
Issued pursuant to dividend reinvestment plan	4,929	60,977
Balance, December 31, 2015	**210,583**	**$4,296,831**
Transfer from contributed surplus on vesting and conversion of share awards	958	14,522
Issued for cash	21,908	115,014
Issuance costs, net of tax	–	(3,706)
Balance, December 31, 2016	**233,449**	**$4,422,661**

On December 12, 2016, Baytex issued 21,907,500 common shares for aggregate gross proceeds of approximately $115.0 million ($109.9 million net of issue costs). Issuance costs of $5.1 million ($3.7 million after tax) were incurred and recorded as a reduction to shareholders' capital.

On April 2, 2015, Baytex issued 36,455,000 common shares for aggregate gross proceeds of approximately $632.5 million ($606.0 million net of issue costs). Issuance costs of $26.4 million ($19.3 million after tax) were incurred and recorded as a reduction to shareholders' capital.

Baytex has a Dividend Reinvestment Plan (the "DRIP") that allows eligible holders in Canada and the United States to reinvest their monthly cash dividends to acquire additional common shares. At the discretion of Baytex, common shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, common shares are issued from treasury at a three percent discount to the arithmetic average of the daily volume weighted average trading prices of the common shares on the Toronto Stock Exchange (in respect of participants resident in Canada or any jurisdiction other than the United States) or the New York Stock Exchange (in respect of participants resident in the United States) for the period commencing on the second business day after the dividend record date and ending on the second business day immediately prior to the dividend payment date. Baytex reserves the right at any time to change or eliminate the discount on common shares acquired through the DRIP from treasury. During the year ended December 31, 2015, a total of 4,928,529 common shares were issued in accordance with this plan.

During the year ended December 31, 2015, the Company declared dividends of $0.80 per share totaling $154.0 million ($96.6 million, net of DRIP). The Company suspended the monthly dividend in September 2015 due to commodity prices and to preserve liquidity.

13. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $13.9 million for the year ended December 31, 2016 ($24.6 million for the year ended December 31, 2015).

The weighted average fair value of share awards granted during the year ended December 31, 2016 was $3.04 per restricted and performance award (for the year ended December 31, 2015, $17.17 per restricted and performance award).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards(1)	Total number of share awards
Balance, December 31, 2014	**747**	**615**	**1,362**
Granted	615	503	1,118
Vested and converted to common shares	(432)	(382)	(814)
Forfeited	(201)	(123)	(324)
Balance, December 31, 2015	**729**	**613**	**1,342**
Granted	1,313	1,583	2,896
Vested and converted to common shares	(450)	(409)	(859)
Forfeited	(84)	(50)	(134)
Balance, December 31, 2016	**1,508**	**1,737**	**3,245**

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

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

For the year ended December 31, 2015, an adjustment of $9.2 million has been recorded to increase both the share-based compensation expense and contributed surplus. Net loss per share (basic and diluted) increased by $0.05 per share to $5.77 per share for the year ended December 31, 2015. As at January 1, 2015, an adjustment of $8.2 million has been recorded to increase both the deficit and contributed surplus. As this adjustment was not material, an opening statement of financial position as at January 1, 2015 is not presented.

14. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income per share based on the net income (loss) attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

	Years Ended December 31					
	2016			2015		
	Net loss	Common shares (000s)	Net loss per share	Net loss	Common shares (000s)	Net loss per share
Net income (loss) – basic	$ (485,184)	212,298	$ (2.29)	$ (1,142,880)	198,207	$ (5.77)
Dilutive effect of share awards	–	–	–	–	–	–
Net income (loss) – diluted	$ (485,184)	212,298	$ (2.29)	$ (1,142,880)	198,207	$ (5.77)

For the year ended December 31, 2016, 3.2 million share awards were anti-dilutive (December 31, 2015 – 1.3 million share awards).

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2016	2015
Net income (loss) before income taxes	$ (757,787)	$(1,487,026)
Expected income taxes at the statutory rate of 27.00% (2015 – 26.24%)(1)	(204,602)	(390,196)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	3,610	6,449
Non-taxable portion of foreign exchange (gain) loss	(5,309)	27,910
Effect of change in income tax rates(1)	1,180	13,246
Effect of rate adjustments for foreign jurisdictions	(63,745)	(120,943)
Effect of change in deferred tax benefit not recognized(2)	(5,309)	40,142
Impairment of goodwill	–	74,025
Other	1,572	5,221
Income tax (recovery)	$ (272,603)	$ (344,146)

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

(2) *A deferred income tax asset has not been recognized for allowable capital losses of $129 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes ($149 million as at December 31, 2015).*

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

Baytex remains confident that the tax filings of the affected entities are correct and in September 2016, filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of CRA; a process that Baytex estimates could take up to two years. If the Appeals Division upholds the notices of reassessment Baytex has the right to appeal to the Tax Court of Canada; a process that Baytex estimates could take a further two years. Should Baytex be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that Baytex estimates could take another two years and potentially longer. The reassessments do not require Baytex to pay any amounts in order to participate in the appeals process.

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

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2016	Recognized in Net Loss	Share Issuance Costs	Foreign Currency Translation Adjustment	**December 31, 2016**
Taxable temporary differences:					
Petroleum and natural gas properties	$(1,105,470)	$ 112,710	$ –	$ 25,181	**$ (967,579)**
Financial derivatives	(29,961)	37,830	–	–	**7,869**
Deferred income	(28,387)	27,968	–	–	**(419)**
Other	(6,595)	2,327	1,370	(2,120)	**(5,018)**
Deductible temporary differences:					
Asset retirement obligations	83,189	10,231	–	(404)	**93,016**
Financial derivatives	1,582	(1,582)	–	–	**–**
Non-capital losses	383,450	30,530	–	(9,028)	**404,952**
Finance costs	46,937	44,547	–	–	**91,484**
Net deferred income tax liability(1)	$ (655,255)	$ 264,561	$ 1,370	$ 13,629	**$ (375,695)**

(1) Non-capital loss carry-forwards at December 31, 2016 totaled $1,191.7 million and expire from 2023 to 2036.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2015	Recognized in Net Loss	Share Issuance Costs	Foreign Currency Translation Adjustment	December 31, 2015
Taxable temporary differences:					
Petroleum and natural gas properties	$ (1,136,083)	$ 188,781	$ –	$ (158,168)	**$ (1,105,470)**
Financial derivatives	(45,950)	15,989	–	–	**(29,961)**
Deferred income	(81,979)	53,592	–	–	**(28,387)**
Other	(7,222)	(10,096)	7,099	3,624	**(6,595)**
Deductible temporary differences:					
Asset retirement obligations	74,918	6,880	–	1,391	**83,189**
Financial derivatives	5,341	(3,759)	–	–	**1,582**
Non-capital losses	227,370	112,802	–	43,278	**383,450**
Finance costs	58,073	(11,136)	–	–	**46,937**
Net deferred income tax liability(1)	$ (905,532)	$ 353,053	$ 7,099	$ (109,875)	**$ (655,255)**

(1) Non-capital loss carry-forwards at December 31, 2015 totaled $1,110.0 million and expire from 2023 to 2035.

16. FINANCING AND INTEREST

	Years Ended December 31	
	2016	2015
Interest on bank loan	**$ 12,860**	$ 14,303
Interest on long-term notes	**90,825**	89,101
Non-cash financing	**4,340**	1,994
Accretion on asset retirement obligations	**6,174**	6,262
Financing and interest	**$ 114,199**	$ 111,660

17. FOREIGN EXCHANGE

	Years Ended December 31	
	2016	2015
Unrealized foreign exchange (gain) loss	**$ (41,436)**	$ 213,999
Realized foreign exchange gain	**(1,242)**	(3,286)
Foreign exchange (gain) loss	**$ (42,678)**	$ 210,713

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan and long-term notes.

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than financial derivatives, bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of financial derivatives are based on mark-to-market values of the underlying financial derivative contracts. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term notes are based on the trading value of the notes.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2016		December 31, 2015		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL(1)					
Cash	**$ 2,705**	**$ 2,705**	$ 247	$ 247	Level 1
Derivatives	**2,219**	**2,219**	110,990	110,990	Level 2
Total FVTPL(1)	**$ 4,924**	**$ 4,924**	$ 111,237	$ 111,237	
Loans and receivables					
Trade and other receivables	**$ 112,171**	**$ 112,171**	$ 98,093	$ 98,093	–
Total loans and receivables	**$ 112,171**	**$ 112,171**	$ 98,093	$ 98,093	
Financial Liabilities					
FVTPL(1)					
Derivatives	**$ (31,365)**	**$ (31,365)**	$ –	$ –	Level 2
Total FVTPL(1)	**$ (31,365)**	**$ (31,365)**	$ –	$ –	
Other financial liabilities					
Trade and other payables	**$ (112,973)**	**$ (112,973)**	$ (267,838)	$ (267,838)	–
Bank loan	**(187,954)**	**(191,286)**	(252,172)	(256,749)	–
Long-term notes	**(1,566,116)**	**(1,435,165)**	(1,602,757)	(1,287,679)	Level 1
Total other financial liabilities	**$ (1,867,043)**	**$ (1,739,424)**	$ (2,122,767)	$ (1,812,266)	

(1) FVTPL means fair value through profit or loss.

There were no transfers between Level 1 and 2 in either 2016 or 2015.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its bank loan and long-term notes, crude oil sales based on U.S. dollar benchmark prices and commodity contracts that are settled in U.S. dollars. The Company's net income (loss), comprehensive income (loss) and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian dollar – U.S. dollar exchange rate. At December 31, 2016, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income (loss) before income taxes by approximately $9.8 million.

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2016	December 31, 2015	**December 31, 2016**	December 31, 2015
U.S. dollar denominated	**US$66,950**	US$124,218	**US$1,197,732**	US$1,240,308

Interest Rate Risk

The Company's interest rate risk arises from the floating rate Revolving Facilities (note 9). As at December 31, 2016, $191.3 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income (loss) before income taxes for the year ended December 31, 2016 by approximately $3.2 million. Baytex uses a combination of short-term and long-term debt to finance operations.

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives are governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities.

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2016, a 10% increase in oil prices would increase the unrealized loss at December 31, 2016 by $39.0 million, while a 10% decrease would decrease the unrealized loss at December 31, 2016 by $41.4 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2016, a 10% increase in natural gas prices would increase the unrealized loss at December 31, 2015 by $6.5 million, while a 10% decrease would decrease the unrealized loss at December 31, 2015 by $8.1 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

	Period	Volume	Price/Unit[1]	Index	Fair Value[3] ($ millions)
Oil					
3-way option[2]	Jan 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI	$ (14.8)
Basis swap	Jan 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS	$ 2.2
Fixed – Sell	Jan 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI	$ (3.2)
Fixed – Sell	Jan 2018 to Dec 2018	2,000 bbl/d	US$54.40	WTI	$ (2.0)
Basis swap[4]	Mar 2017 to Jun 2017	1,000 bbl/d	WTI less US$14.30	WCS	$ –
Basis swap[4]	Apr 2017 to Jun 2017	2,000 bbl/d	WTI less US$13.50	WCS	$ –
Basis swap[4]	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$14.25	WCS	$ –
Natural Gas					
Fixed – Sell	Jan 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX	$ (7.2)
Fixed – Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX	$ (0.5)
Fixed – Sell	Jan 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO	$ (3.3)
Fixed – Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$ (0.3)
Total					**$ (29.1)**
Current asset					$ 2.2
Current liability					$ (28.5)
Non-current liability					$ (2.8)

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.
(3) Fair values as at December 31, 2016. For the purposes of the table, contracts entered subsequent to December 31, 2016 will have no fair value assigned.
(4) Contracts entered subsequent to December 31, 2016.

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

	Years Ended December 31	
	2016	2015
Realized financial derivatives gain	**$ (96,929)**	$ (197,545)
Unrealized financial derivatives loss – commodity	**140,136**	54,318
Unrealized financial derivatives loss – redemption feature on long-term notes	**–**	498
Financial derivatives loss (gain)	**$ 43,207**	$ (142,729)

Physical Delivery Contracts

The following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Price/Unit[1]
WCS Blend[2]	Mar 2017 to Jun 2017	2,000 bbl/d	WTI less US$14.33

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Contracts entered subsequent to December 31, 2016.

As at December 31, 2016, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

	Period	Term volume
Raw bitumen	Jan 2017 to Mar 2017	5,650 bbl/d
Raw bitumen	Apr 2017 to Dec 2017	5,000 bbl/d

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures. As at December 31, 2016, Baytex had available unused bank credit facilities in the amount of $580.8 million (as at December 31, 2015 – $820.1 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2016 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 112,973	$ 112,973	$ –	$ –	$ –
Bank loan[(1)(2)]	191,286	–	191,286	–	–
Long-term notes[(2)]	1,584,158	–	–	747,078	837,080
Interest on long-term notes[(3)]	404,769	64,325	128,650	127,847	83,947
	$ 2,293,186	$ 177,298	$ 319,936	$ 874,925	$ 921,027

(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.

(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit and/or parental guarantees may be obtained prior to the commencement of business with certain counterparties. None of the Company's financial assets are secured by any other type of collateral. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on accounts receivable at December 31, 2016 relates to accrued revenues for December 2016. Accounts receivables from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At December 31, 2016, $17.8 million of accounts receivable relates to joint interest receivables from the operator of our joint operations in the Eagle Ford.

Should Baytex determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income (loss). If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. For the year ended December 31, 2016, there were no changes to the allowance for doubtful accounts (2015 – $0.1 million added).

As at December 31, 2016, allowance for doubtful accounts was $1.4 million (2015 – $1.4 million). In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2016, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $0.9 million (2015 – $1.4 million).

The Company's trade and other receivables were aged as follows at December 31, 2016:

Trade and Other Receivables Aging[1]	December 31, 2016
Current (less than 30 days)	$ **82,968**
31-60 days	**1,234**
61-90 days	**288**
Past due (more than 90 days)	**934**
	$ **85,424**

(1) Excludes $24.7 million of cash calls paid to the operator of our U.S. properties and $2.1 million of prepaid expenses that have been classified as trade and other receivables.

19. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2016	2015
Trade and other receivables	$ (14,078)	$ 105,425
Trade and other payables	(154,865)	(130,423)
	$ (168,943)	$ (24,998)
Changes in non-cash working capital related to:		
Operating activities	$ (23,270)	$ 43,891
Investing activities	(135,743)	(70,968)
Current income tax paid on dispositions	–	(8,181)
Foreign currency translation on non-cash working capital	(9,930)	10,260
	$ (168,943)	$ (24,998)

Onerous Contracts

Onerous contracts result from unfavorable leases in which the unavoidable costs of meeting the obligations under the contracts exceed the economic benefits expected to be received.

	Amount
Balance, December 31, 2014 and 2015	$ –
Liabilities incurred	10,116
Liabilities settled	(770)
Foreign currency translation	158
Balance, December 31, 2016	$ **9,504**

As at December 31, 2016, the Company has a provision totaling $9.5 million related to onerous contracts (December 31, 2015 – nil). The provision represents the difference between the minimum future payments that we are required to make and the estimated recoveries. During the year ended December 31, 2016, the Company recognized $10.1 million of losses on onerous contracts relating to an office sublease and a transportation agreement which were recorded in other expense (income).

Income Statement Presentation

Baytex's consolidated statements of income (loss) and comprehensive income (loss) are prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2016	2015
Operating	$ 9,528	$ 13,180
General and administrative	23,070	28,432
Total employee compensation costs	$ 32,598	$ 41,612

20. COMMITMENTS AND CONTINGENCIES

Baytex has 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 cash flow 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, 2016, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Operating leases	$ 38,982	$ 8,164	$ 15,511	$ 12,679	$ 2,628
Processing agreements	48,833	9,631	11,130	9,043	19,029
Transportation agreements	59,172	10,998	23,670	22,674	1,830
Total	$ 146,987	$ 28,793	$ 50,311	$ 44,396	$ 23,487

Baytex also has 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.

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2016 were $7.7 million (December 31, 2015 – $8.0 million). Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has the option to renew or extend the leases on its office building with the new lease terms to be based on current market prices. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

The litigation and claims that Baytex is engaged with, which arose in the normal course of operations, are not expected to materially affect the Company's financial position or reported results of operations.

21. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transactions with key management personnel (including directors) are noted in the table below:

	Years Ended December 31	
	2016	2015
Short-term employee benefits	$ 7,278	$ 6,831
Share-based compensation	6,613	12,032
Termination payments	–	549
Total compensation for key management personnel	$ 13,891	$ 19,412

22. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of its business through maintenance of investor, creditor and market confidence.

Baytex considers its capital structure to include net debt and shareholders' equity. Baytex monitors capital based on the current and projected ratio of net debt to funds from operations and the current and projected level of its undrawn credit facilities. Historically and under normal operating conditions, the Company's objective is to maintain a net debt to funds from operations ratio of less than two times and to have access to undrawn credit facilities of not less than $100 million. The net debt to funds from operations ratio may increase beyond two times and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors including changes to commodity prices, acquisitions, and changes in the credit market.

These objectives and strategy are reviewed on an annual basis. With the significant decrease in commodity prices, Baytex's net debt to funds from operations ratio has exceeded its target but the Company has maintained access to at least $100 million in undrawn credit facilities. The Company's financial strategy is designed to maintain a flexible capital structure consistent with the objectives stated above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to manage its capital, the Company may adjust its level of capital spending, issue new shares or debt, adjust the amount of its dividends or sell assets to reduce debt. In the current commodity environment the Company's objective is to have access to undrawn credit facilities of not less than $100 million and to manage its capital to maintain liquidity.

As at December 31, 2016, Baytex is in compliance with all financial covenants relating to its senior unsecured notes and Revolving Facilities.

	Years Ended December 31	
	2016	2015
Cash flow from operating activities	$ 247,365	$ 549,420
Change in non-cash working capital	23,270	(43,891)
Asset retirement expenditures	5,616	10,888
Funds from operations(1)	$ 276,251	$ 516,417

	As at December 31	
	2016	2015
Bank loan – principal	$ 191,286	$ 256,749
Long-term notes – principal	1,584,158	1,623,658
Trade and other payables	112,973	267,838
Cash	(2,705)	(247)
Trade and other receivables	(112,171)	(98,093)
Net debt(1)	$ 1,773,541	$ 2,049,905

(1) Funds from operations and net debt as presented does not have any standardized meaning prescribed by IFRS and, therefore, they may not be comparable with the calculation of similar measures for other entities.

	As at December 31	
	2016	2015
Available undrawn credit facilities	$ 580,767	$ 820,051
Net debt to funds from operations ratio	6.4	4.0

23. SUBSEQUENT EVENT

On January 20, 2017, Baytex acquired heavy oil properties in the Peace River area of Alberta for total consideration of $66 million. The consideration paid consists of $91 million of oil and gas assets, $5 million of accounts payable and $20 million of asset retirement obligations. The acquisition provides additional development opportunities and the acquired properties are located immediately adjacent to Baytex's existing Peace River lands.

Petroleum and Natural Gas Reserves as at December 31, 2016

Baytex's year-end 2016 proved and probable reserves were evaluated by Sproule Unconventional Limited ("Sproule") and Ryder Scott Company, L.P. ("Ryder Scott"), both independent qualified reserves evaluators. Sproule prepared our reserves report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's December 31, 2016 forecast price and cost assumptions. Ryder Scott also evaluated the possible reserves associated with our Eagle Ford assets. All Baytex oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Finding and development ("F&D") and finding, development and acquisition ("FD&A") costs are all reported inclusive of future development costs ("FDC"). Our 2016 reserves report does not include the acquisition of additional heavy oil assets in the Peace River region that closed on January 20, 2017. The following table sets forth our gross and net reserves volumes at December 31, 2016 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA

	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
Proved						
Developed Producing	25,923	19,717	382	347	1,985	1,858
Developed Non-Producing	2,609	2,223	7,655	7,072	–	–
Undeveloped	18,343	16,172	5,428	4,357	308	316
Total Proved	46,875	38,112	13,465	11,776	2,293	2,174
Probable	29,325	23,955	55,835	44,311	1,794	1,598
Total Proved Plus Probable	76,199	62,068	69,300	56,086	4,087	3,773

CANADA

	Forecast Prices and Costs					
	Natural Gas Liquids[3]		Conventional Natural Gas[4]		Oil Equivalent[5]	
Reserves Category	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mbbl)	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mboe)*	*(mboe)*
Proved						
Developed Producing	1,246	925	49,201	43,294	37,735	30,063
Developed Non-Producing	–	–	22	35	10,267	9,302
Undeveloped	1,345	1,114	66,711	60,907	36,542	32,110
Total Proved	2,590	2,039	115,933	104,236	84,544	71,475
Probable	3,198	2,479	89,206	76,579	105,019	85,106
Total Proved Plus Probable	5,788	4,518	205,139	180,816	189,564	156,581

UNITED STATES

Reserves Category	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids(3)		Shale Gas	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*
Proved						
Developed Producing	19,242	14,101	26,907	19,861	60,929	45,025
Developed Non-Producing	–	–	–	–	–	–
Undeveloped	30,472	22,344	53,194	39,199	112,899	83,277
Total Proved	49,714	36,444	80,102	59,059	173,828	128,302
Probable	8,399	6,161	28,627	21,025	59,075	43,371
Total Proved Plus Probable	58,113	42,605	108,728	80,084	232,903	171,674
Possible(6)(7)	19,269	14,160	37,430	27,545	81,346	59,866
Total Proved Plus Probable Plus Possible	77,381	56,765	146,158	107,629	314,249	231,540

UNITED STATES

Reserves Category	Forecast Prices and Costs			
	Conventional Natural Gas(4)		Oil Equivalent(5)	
	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mmcf)	*(mmcf)*	*(mboe)*	*(mbbl)*
Proved				
Developed Producing	27,530	20,206	60,892	44,833
Developed Non-Producing	–	–	–	–
Undeveloped	28,553	20,950	107,242	78,914
Total Proved	56,083	41,156	168,134	123,747
Probable	8,906	6,543	48,355	35,505
Total Proved Plus Probable Possible	64,988	47,699	216,490	159,252
Possible(6)(7)	18,327	13,477	73,310	53,928
Total Proved Plus Probable Plus Possible	83,315	61,176	289,800	213,180

TOTAL

Reserves Category	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
Proved						
Developed Producing	25,923	19,717	382	347	1,985	1,858
Developed Non-Producing	2,609	2,223	7,655	7,072	–	–
Undeveloped	18,343	16,172	5,428	4,357	308	316
Total Proved	46,875	38,112	13,465	11,776	2,293	2,174
Probable	29,325	23,955	55,835	44,311	1,794	1,598
Total Proved Plus Probable	76,199	62,068	69,300	56,086	4,087	3,773
Possible(6)(7)	–	–	–	–	–	–
Total Proved Plus Probable Plus Possible	76,199	62,068	69,300	56,086	4,087	3,773

TOTAL

Reserves Category	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids[3]		Shale Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*
Proved						
Developed Producing	19,242	14,101	28,153	20,786	60,929	45,025
Developed Non-Producing	–	–	–	–	–	–
Undeveloped	30,472	22,344	54,539	40,312	112,899	83,277
Total Proved	49,714	36,444	82,692	61,099	173,828	128,302
Probable	8,399	6,161	31,825	23,504	59,075	43,371
Total Proved Plus Probable	58,113	42,605	114,516	84,602	232,903	171,674
Possible[6][7]	19,269	14,160	37,430	27,545	81,346	59,866
Total Proved Plus Probable Plus Possible	77,381	56,765	151,946	112,147	314,249	231,540

TOTAL

Reserves Category	Forecast Prices and Costs			
	Conventional Natural Gas[4]		Oil Equivalent[5]	
	Gross[1]	Net[2]	Gross[1]	Net[2]
	(mmcf)	*(mmcf)*	*(mboe)*	*(mboe)*
Proved				
Developed Producing	76,731	63,501	98,627	74,896
Developed Non-Producing	21	35	10,267	9,302
Undeveloped	95,264	81,857	143,784	111,024
Total Proved	172,016	145,392	252,678	195,222
Probable	98,112	83,123	153,375	120,611
Total Proved Plus Probable	270,127	228,515	406,053	315,832
Possible[6][7]	18,327	13,477	73,310	53,928
Total Proved Plus Probable Plus Possible	288,455	241,992	479,364	369,760

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(6) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(7) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves[1][2]
By Principal Product Type
Forecast Prices and Costs

	Heavy Oil[3]			Bitumen		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640
Extensions	227	1,255	1,482	–	–	–
Infill Drilling	1,037	1,024	2,062	–	–	–
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	(8,004)	(9,862)	(17,866)	476	(216)	260
Discoveries	–	–	–	–	–	–
Acquisitions	34	13	48	–	–	–
Dispositions	(685)	(804)	(1,489)	–	–	–
Economic Factors	(2,700)	(185)	(2,885)	(204)	170	(35)
Production	(8,065)	–	(8,065)	(565)	–	(565)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300

	Light and Medium Crude Oil			Tight Oil[4]		
Gross Reserves Category	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
December 31, 2015	2,902	2,420	5,323	49,215	4,551	53,765
Extensions	–	–	–	–	–	–
Infill Drilling	–	–	–	6,948	5,863	12,812
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	141	(425)	(284)	(1,723)	(2,027)	(3,750)
Discoveries	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–
Dispositions	(25)	(8)	(32)	(831)	(52)	(883)
Economic Factors	(214)	(194)	(408)	3	63	67
Production	(511)	–	(511)	(3,898)	–	(3,898)
December 31, 2016	2,293	1,794	4,087	49,714	8,399	58,113

Gross Reserves Category	Natural Gas Liquids(4)(5) Proved	Probable	Proved + Probable	Shale Gas(4) Proved	Probable	Proved + Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mmcf)*
December 31, 2015	86,454	19,344	105,798	194,767	40,038	234,805
Extensions	–	148	148	–	–	–
Infill Drilling	15,692	21,905	37,597	33,171	43,893	77,064
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	(12,676)	(9,662)	(22,338)	(41,058)	(25,187)	(66,246)
Discoveries	–	–	–	–	–	–
Acquisitions	106	27	133	–	–	–
Dispositions	(149)	(24)	(174)	–	–	–
Economic Factors	95	88	183	334	331	665
Production	(6,830)	–	(6,830)	(13,386)	–	(13,386)
December 31, 2016	82,692	31,825	114,516	173,828	59,075	232,903

Gross Reserves Category	Conventional Natural Gas(6)(7) Proved	Probable	Proved + Probable	Oil Equivalent(8) Proved	Probable	Proved + Probable
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mboe)*	*(mboe)*	*(mboe)*
December 31, 2015	148,880	91,529	240,409	274,633	142,008	416,640
Extensions	11	3,682	3,693	229	2,017	2,245
Infill Drilling	7,749	5,094	12,843	30,497	36,957	67,455
Improved Recoveries	–	–	–	–	–	–
Technical Revisions	36,875	520	37,395	(22,483)	(26,303)	(48,786)
Discoveries	–	–	–	–	–	–
Acquisitions	2,531	641	3,172	562	147	709
Dispositions	(2,615)	(619)	(3,235)	(2,126)	(992)	(3,118)
Economic Factors	(1,428)	(2,735)	(4,163)	(3,202)	(460)	(3,661)
Production	(19,987)	–	(19,987)	(25,431)	–	(25,431)
December 31, 2016	172,016	98,112	270,127	252,679	153,375	406,053

Notes:

(1) *"Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.*

(2) *Reserves information as at December 31, 2016 and 2015 is prepared in accordance with NI 51-101.*

(3) *Technical revisions related to heavy oil are largely attributable to revised reservoir and mobility mapping and well performance.*

(4) *Technical revisions for tight oil, natural gas liquids and shale gas were largely the result of the development of additional horizons, primarily the Upper Eagle Ford. These new horizons are now proven and have producing wells and new locations, which reduced the expected recovery from a portion of the existing wells. These technical revisions were more than offset by reserve additions classified as "infill drilling".*

(5) *Natural gas liquids include condensate.*

(6) *Conventional natural gas includes associated, non-associated and solution gas.*

(7) *Technical revisions related to conventional natural gas are largely attributable to solution gas conservation at Peace River.*

(8) *Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves (excluding thermal reserves) at year-end 2016 by annualized Q4/2016 production.

	Q4/2016 Actual Production	Reserves Life Index (years) Proved	Proved Plus Probable
Oil and NGL (bbl/d)	51,464	9.7	13.5
Natural Gas (mcf/d)	82,032	11.6	16.8
Oil Equivalent (boe/d)	65,136	10.1	14.2

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital programs (including FDC) is summarized in the following table.

	2016	2015	2014	Three-Year Total/Average 2014 - 2016
Capital Expenditures ($ millions)				
Exploration and development	$ 224.8	$ 521.0	$ 766.1	$ 1,511.9
Acquisitions (net of dispositions)	(63.6)	1.6	2,545.1	2,483.1
Total	$ 161.2	$ 522.7	$3,311.2	$ 3,995.0
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$(219.4)	$ (397.9)	$ (248.5)	$ (865.8)
Acquisitions (net of dispositions)	7.6	6.0	1,312.9	1,326.5
Total	$(211.8)	$ (391.9)	$1,064.4	$ 460.7
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$ 108.8	$ (399.9)	$ (102.0)	$ (393.1)
Acquisitions (net of dispositions)	1.9	0.5	1,210.5	1,1212.9
Total	$ 110.7	$ (399.4)	$1,108.5	$ 819.8
Proved Reserves Additions (mboe)				
Exploration and development	5,041	21,729	83,515	110,285
Acquisitions (net of dispositions)	(1,564)	537	68,824	67,797
Total	3,477	22,266	152,339	178,082
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	17,253	15,782	33,598	66,633
Acquisitions (net of dispositions)	(2,408)	126	108,515	106,233
Total	14,844	15,908	142,113	172,865
F&D costs ($/boe)(1)				
Proved	$ 1.07	$ 5.67	$ 6.20	$ 5.86
Proved plus probable	$ 19.33	$ 7.68	$ 19.77	$ 16.79
FD&A costs ($/boe)(2)				
Proved	$ –(5)	$ 5.88	$ 28.72	$ 25.02
Proved plus probable	$ 18.33	$ 7.75	$ 31.10	$ 27.86
Ratios (based on proved plus probable reserves)				
Production replacement ratio(3)	58%	52%	497%	204%
Recycle ratio(4)	1.0x	2.9x	1.9x	1.9x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures) divided by total reserves additions.

(3) Production Replacement Ratio is calculated as total reserves additions (including acquisitions and divestitures) divided by annual production.

(4) Recycle Ratio is calculated as operating netback divided by F&D costs (proved plus probable including FDC). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, operating expenses and transportation expenses. For 2016, recycle ratio is calculated based on a Q4/2016 operating netback of $19.24/boe.

(5) 2016 FD&A costs were negative due to the reduction in estimated Future Development Costs.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes Sproule and Ryder Scott's estimate of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

CANADA

	Summary of Net Present Value of Future Net Revenue As at December 31, 2016 Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$ 523,531	$ 467,725	$ 420,445	$ 381,377	$ 349,129
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	534,063	386,333	283,491	210,063	156,424
Total Proved	1,300,931	1,022,460	825,145	681,804	575,038
Probable	2,182,301	1,195,885	723,254	467,328	314,943
Total Proved Plus Probable	$3,483,233	$2,218,345	$1,548,399	$1,149,132	$ 889,981

UNITED STATES

Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$1,674,035	$1,286,547	$1,047,642	$ 888,644	$ 776,258
Developed Non-Producing					
Undeveloped	2,328,597	1,416,589	914,698	615,838	426,453
Total Proved	4,002,633	2,703,136	1,962,340	1,504,482	1,202,712
Probable	1,053,807	604,633	376,915	249,067	171,338
Total Proved Plus Probable	5,056,440	3,307,769	2,339,255	1,753,549	1,374,049
Possible(1)	2,370,364	1,417,370	938,108	668,947	504,293
Total Proved Plus Probable Plus Possible(1)	$7,426,804	$4,725,138	$3,277,363	$2,422,496	$1,878,343

TOTAL

Reserves Category	0%	5%	10%	15%	20%
	($000s)	*($000s)*	*($000s)*	*($000s)*	*($000s)*
Proved					
Developed Producing	$ 2,197,567	$ 1,754,271	$ 1,468,087	$ 1,270,022	$ 1,125,387
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	2,862,660	1,802,922	1,198,190	825,901	582,878
Total Proved	5,303,564	3,725,596	2,787,485	2,186,286	1,777,750
Probable	3,236,109	1,800,518	1,100,168	716,395	486,281
Total Proved Plus Probable	8,539,673	5,526,114	3,887,653	2,902,681	2,264,031
Possible(1)(2)	2,370,364	1,417,370	938,108	668,947	504,293
Total Proved Plus Probable Plus Possible(1)(2)	$10,910,037	$ 6,943,484	$ 4,825,762	$ 3,571,628	$ 2,768,324

Notes:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2016.

Year	WTI Cushing *US$/bbl*	Canadian Light Sweet *C$/bbl*	Western Canada Select *C$/bbl*	Henry Hub *US$/MMbtu*	AECO-C Spot *C$/MMbtu*	Operating Cost Inflation Rate *%/Yr*	Capital Cost Inflation Rate *%/Yr*	Exchange Rate *$US/$Cdn*
2016 act.	43.32	52.80	38.30	2.55	2.18	1.6	(3.3)	0.755
2017	55.00	65.58	53.12	3.50	3.44	0.0	0.0	0.780
2018	65.00	74.51	61.85	3.50	3.27	2.0	2.0	0.820
2019	70.00	78.24	64.94	3.50	3.22	2.0	2.0	0.850
2020	71.40	80.64	66.93	4.00	3.91	2.0	2.0	0.850
2021	72.83	82.25	68.27	4.08	4.00	2.0	2.0	0.850
2022	74.28	83.90	69.64	4.16	4.10	2.0	2.0	0.850
2023	75.77	85.58	71.03	4.24	4.19	2.0	2.0	0.850
2024	77.29	87.29	72.45	4.33	4.29	2.0	2.0	0.850
2025	78.83	89.03	73.90	4.42	4.40	2.0	2.0	0.850
2026	80.41	90.81	75.38	4.50	4.50	2.0	2.0	0.850
2027	82.02	92.63	76.88	4.59	4.61	2.0	2.0	0.850
Thereafter	Escalation rate of 2.0%							

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

($000s)	Future Development Costs As of December 31, 2016 Forecast Prices and Costs					
	CANADA		UNITED STATES		TOTAL	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2017	$ 68,851	$ 82,101	$ 171,137	$ 252,541	$ 239,989	$ 334,642
2018	130,105	273,039	192,088	247,526	322,193	520,564
2019	118,115	279,336	200,143	267,560	318,258	546,896
2020	63,573	162,254	168,708	245,334	232,280	407,588
2021	36,081	138,682	215,465	282,523	251,546	421,204
Remaining	15,550	303,996	395,073	551,698	410,623	855,693
Total (undiscounted)	$432,275	$1,239,406	$1,342,613	$1,847,182	$1,774,888	$3,086,588

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2016.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	554,178	489,669
Saskatchewan	119,004	113,440
Total Canada	673,182	603,109
United States		
Texas	3,038	2,535
Total Company	676,220	605,644

We estimate the value of our net undeveloped land holdings at December 31, 2016 to be approximately $67 million. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before tax, as estimated by the Company's independent reserves engineers, Sproule and Ryder Scott, at year-end, plus the estimated value of our undeveloped acreage, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves evaluators.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of possible reserves or contingent resources. As we execute our capital programs, we expect to convert possible reserves and contingent resources to reserves which may result in an increase in booked proved plus probable reserves.

The following table sets forth our net asset value as at December 31, 2016.

($ millions except per share amounts)	Net Asset Value Forecast Prices and Costs (before tax) and Discounted at (%/year) 5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$ 5,526	$ 3,888	$ 2,903
Undeveloped acreage[(1)]	67	67	67
Asset retirement obligations[(2)]	(136)	(69)	(46)
Net debt	(1,774)	(1,774)	(1,774)
Net Asset Value	$ 3,683	$ 2,112	$ 1,150
Net Asset Value per Share[(3)]	$ 15.78	$ 9.05	$ 4.93

Notes:

(1) Undeveloped acreage value generally represents the estimated replacement cost of our undeveloped land.

(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.

(3) Based on 233.4 million common shares outstanding as at December 31, 2016.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Lloydminster, Peace River, Northeast Alberta and Pembina areas in Canada. We commissioned Ryder Scott to audit our internal evaluation of our contingent resources in the Eagle Ford area of Texas. Both assessments were effective December 31, 2016, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

Contingent resources represent the quantity of oil and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of our contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided are estimates. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided.

The contingent resources described below represent our gross interests (unless otherwise indicated) and are a best estimate. A "best estimate" is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources identified in the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources herein are presented as deterministic cumulative best estimate volumes.

Our contingent resources fall within the development pending and development unclarified sub-classes, which are defined as follows:

- Development Pending – are economic contingent resources that have a high chance of development. Contingencies are directly influenced by the developer, are actively being pursued and resolution is expected in a reasonable time period.
- Development Unclarified – are contingent resources that have a chance of development which is difficult to assess, and have an economic status which is undetermined. Projects are currently under evaluation and therefore contingencies are not clearly defined. Progress is expected within a reasonable time period.

Development Pending

The following table summarizes the status of our development pending contingent resources.

Area	Product Type	Project Status	Future Development Costs ($ millions)[1]	Timing of First Commercial Production	Recovery Technology
		Development Pending – Project Status			
Peace River	Bitumen	Development Study	$129	2019-2021	Cyclic steam stimulation ("CSS")
Peace River, Lloydminster and Northeast Alberta	Heavy Oil	Development Study	$ 94	2017-2023	Horizontal, vertical and multilateral well development
Pembina	Light & Medium Oil, Natural Gas	Development Study	$ 13	2022	Horizontal well development with multi-stage fracturing completion
Eagle Ford	Tight Oil, Shale Gas and NGL	Development Study	$152	2017-2028	Horizontal well development with multi-stage fracturing completion

Note:

(1) Undiscounted and unrisked.

The following table presents a summary of the quantitative risk of the chance of development we have applied to our development pending contingent resources.

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)	Risked NPV[2] Discounted at 10% (before tax) ($ millions)
	Development Pending – Chance of Development Risk[1]				
Peace River	Bitumen	19	81%	16	70
Peace River, Lloydminster and Northeast Alberta	Heavy Oil	6	86%	5	23
Pembina	Light & Medium Oil, Natural Gas	2	90%	2	10
Eagle Ford	Tight Oil, Shale Gas and NGL	14	80%	11	107
Total		41		34	210

Notes:

(1) Numbers may not add due to rounding.

(2) An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.

The principal risks that would influence the development of the Lloydminster, Northeast Alberta, Peace River and Pembina development pending contingent resources are: the timing of regulatory approvals to expand the project areas; the results of delineation drilling and seismic activity necessary for project development; the ability of these projects to compete for capital against our other projects; our corporate commitment to the timing of development; and the commodity price levels affecting the economic viability bitumen and heavy oil production in Alberta. The principal risks specific to the development of the Eagle Ford development pending contingent resources are: our reliance on the operator's capital commitment and development timing; the ability of these projects to compete for capital against our other projects; and the possibility of inter-well communication from infill drilling.

Development Unclarified

Our development unclarified contingent resources are conceptual project scenarios with no specific company defined development plan in the near-term. The following table presents a summary of the quantitative risk of the chance of development we have applied to our development unclarified contingent resources.

	Development Unclarified – Chance of Development Risk[(1)]			
Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)
Peace River and Northeast Alberta	Bitumen	943	58%	551
Peace River, Lloydminster and Northeast Alberta	Heavy Oil	29	56%	16
Pembina	Light & Medium Oil, Natural Gas	12	55%	7
Eagle Ford	Tight Oil, Shale Gas and NGL	120	50%	60
Total		1,103		634

Note:

(1) Numbers may not add due to rounding.

In addition to the risks identified for the development pending sub-class, the projects in the Lloydminster, Northeast Alberta, Peace River and Pembina areas development unclarified sub-class are also subject to risks pertaining to commercial productivity of the reservoirs. The geological complexity and variability in these reservoirs may require the implementation of pilot projects to test the viability of CSS and SAGD thermal recovery technologies. The risks outlined for the contingent resources in the Eagle Ford development pending sub-class also apply to the development unclarified sub-class but are greater in magnitude.

Additional disclosures related to our contingent resources are included in Appendix A to our Annual Information Form for the year ended December 31, 2016, which was filed on March 7, 2017.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report have been prepared in accordance with National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities” of the Canadian Securities Administrators (“NI 51-101”). Complete NI 51-101 reserves disclosure are included in our Annual Information Form for the year ended December 31, 2016, which was filed on March 7, 2017. Listed below are cautionary statements that are specifically required by NI 51-101:

- Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- This reoprt contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

This report contains estimates as of December 31, 2016 of the volumes of “contingent resources” attributable to our properties. These estimates were prepared by independent qualified reserves evaluators.

“Contingent resources” are not, and should not be confused with, petroleum and natural gas reserves. “Contingent resources” are defined in the Canadian Oil and Gas Evaluation Handbook as: “those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.”

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future.

The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Baytex Energy Corp.

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Chief Executive Officer
Baytex Energy Corp.

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Chairman
Burnet, Duckworth & Palmer LLP

Edward Chwyl[2,3]
Lead Independent Director
Independent Businessman

Trudy M. Curran[1,4]
Independent Businesswoman

Naveen Dargan[1,2]
Independent Businessman

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

Gregory K. Melchin[1,4]
Independent Businessman

Mary Ellen Peters[1,2]
Independent Businesswoman

Dale O. Shwed[3]
President & Chief Executive Officer
Crew Energy Inc.

1 Member of the Audit Committee
2 Member of the Compensation Committee
3 Member of the Reserves Committee
4 Member of the Nominating and Governance Committee

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OFFICERS

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Edward D. LaFehr
President

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

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

Kendall D. Arthur
Vice President, Lloydminster
and Conventional Business Units

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

Cameron A. Hercus
Vice President,
Corporate Development

Ryan M. Johnson
Vice President,
Peace River Business Unit

Chad L. Kalmakoff
Vice President, Finance

Gregory A. Sawchenko
Vice President, Land

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

AUDITOR

KPMG LLP

BANKERS

Bank of Nova Scotia

Alberta Treasury Branches

Bank of America

Bank of Montreal

Barclays Bank plc

Canadian Imperial Bank
of Commerce

Caisse Centrale Desjardins

National Bank of Canada

Royal Bank of Canada

Société Générale

The Toronto-Dominion Bank

Union Bank

Wells Fargo Bank

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited

Ryder Scott Company, L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: **BTE**

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ENERGY CORP.

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