BAYTEX
ENERGY CORP.

Q2 REPORT 2017

PRESS RELEASE

“Driven by excellent capital efficiencies across our portfolio, we have been able to substantially grow production largely within funds from operations during the first half of the year at US$50/bbl oil prices. This is due to some of the strongest well results we have seen to-date in the Eagle Ford and a safe and highly efficient start-up of our development program in Canada. Our team is pushing to reposition the business for success at these low commodity prices with production currently above the high end of guidance and capital expenditures tracking toward the low end of guidance,” commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 72,812 boe/d (79% oil and NGL) during Q2/2017, an increase of 5% from Q1/2017 and 12% from Q4/2016;
- Delivered funds from operations ("FFO") of $83.1 million ($0.35 per basic share) in Q2/2017 and $164.5 million ($0.70 per basic share) in H1/2017;
- Produced 38,528 boe/d in the Eagle Ford, an increase of 7% from Q1/2017 and 15% from Q4/2016, and 34,284 boe/d in Canada, an increase of 3% from Q1/2017 and 8% from Q4/2016;
- Established average 30-day initial gross production rates of approximately 2,150 boe/d per well from three recently completed pads (total of 11 wells) in the oil window of our Eagle Ford acreage;
- Realized an operating netback (sales price less royalties, operating and transportation expenses) in Q2/2017 of $18.30/boe ($18.70/boe including financial derivatives gain);
- Reduced annual guidance for operating expenses by 4% (at mid-point) to $10.75-$11.25/boe, reflecting strong performance in H1/2017 of $10.50/boe; and
- Tightened our 2017 production guidance range to 69,000 to 70,000 boe/d (previously 68,000 to 70,000 boe/d) and exploration and development capital expenditures to $310 to $330 million (previously $325 to $350 million).

	Three Months Ended			Six Months Ended	
	June 30, 2017	March 31, 2017	June 30, 2016	**June 30, 2017**	June 30, 2016
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 274,369**	$ 260,549	$ 195,733	**$ 534,918**	$ 349,331
Funds from operations (1)	**83,136**	81,369	81,261	**164,505**	126,906
Per share - basic	**0.35**	0.35	0.39	**0.70**	0.60
Per share - diluted	**0.35**	0.34	0.39	**0.70**	0.60
Net income (loss)	**9,268**	11,096	(86,937)	**20,364**	(86,330)
Per share - basic	**0.04**	0.05	(0.41)	**0.09**	(0.41)
Per share - diluted	**0.04**	0.05	(0.41)	**0.09**	(0.41)
Exploration and development	**78,007**	96,559	35,490	**174,566**	117,175
Acquisitions, net of divestitures	**5,226**	66,004	(37)	**71,230**	(46)
Total oil and natural gas capital expenditures	**$ 83,233**	$ 162,563	$ 35,453	**$ 245,796**	$ 117,129
Bank loan (2)	**$ 264,032**	$ 259,966	$ 347,083	**$ 264,032**	$ 347,083
Long-term notes (2)	**1,541,694**	1,574,116	1,544,181	**1,541,694**	1,544,181
Long-term debt	**1,805,726**	1,834,082	1,891,264	**1,805,726**	1,891,264
Working capital deficiency	**13,661**	16,827	51,247	**13,661**	51,274
Net debt (3)	**$ 1,819,387**	$ 1,850,909	$ 1,942,538	**$ 1,819,387**	$ 1,942,538

	Three Months Ended			Six Months Ended	
	June 30, 2017	March 31, 2017	June 30, 2016	**June 30, 2017**	June 30, 2016
OPERATING					
Daily production					
Heavy oil (bbl/d)	**25,577**	24,625	22,423	**25,104**	23,615
Light oil and condensate (bbl/d)	**22,370**	21,617	21,894	**21,996**	23,191
NGL (bbl/d)	**9,693**	8,306	9,834	**9,003**	9,971
Total oil and NGL (bbl/d)	**57,640**	54,548	54,151	**56,103**	56,777
Natural gas (mcf/d)	**91,028**	88,502	95,281	**89,771**	96,750
Oil equivalent (boe/d @ 6:1) (4)	**72,812**	69,298	70,031	**71,065**	72,902
Benchmark prices					
WTI oil (US$/bbl)	**48.29**	51.91	45.60	**50.10**	39.53
WCS heavy oil (US$/bbl)	**37.16**	37.34	32.29	**37.25**	25.76
Edmonton par oil ($/bbl)	**61.92**	63.98	54.78	**62.95**	47.80
LLS oil (US$/bbl)	**49.70**	52.50	46.20	**51.10**	39.73
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**37.62**	35.96	30.09	**36.81**	20.87
Light oil and condensate ($/bbl)	**60.68**	63.26	52.42	**61.94**	44.79
NGL ($/bbl)	**22.70**	26.35	13.28	**24.38**	15.86
Total oil and NGL ($/bbl)	**44.06**	45.31	36.07	**44.67**	29.76
Natural gas ($/mcf)	**3.62**	3.52	1.94	**3.57**	2.17
Oil equivalent ($/boe)	**39.41**	40.16	30.52	**39.77**	26.06
CAD/USD noon rate at period end	**1.2983**	1.3322	1.3009	**1.2983**	1.3009
CAD/USD average rate for period	**1.3447**	1.3229	1.2885	**1.3338**	1.3317
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**4.81**	6.97	9.04	**6.97**	9.04
Low	**2.87**	4.02	4.85	**2.87**	1.57
Close	**3.15**	4.54	7.50	**3.15**	7.50
Volume traded (thousands)	**216,383**	255,645	466,201	**472,026**	949,511
NYSE					
Share price (US$)					
High	**3.63**	5.19	7.14	**5.20**	7.14
Low	**2.15**	3.01	3.67	**2.15**	1.08
Close	**2.43**	3.65	5.79	**2.43**	5.79
Volume traded (thousands)	**109,758**	136,666	198,514	**248,931**	352,567
Common shares outstanding (thousands)	**234,204**	234,203	210,715	**234,204**	210,715

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 three and six months ended June 30, 2017.

(2) Principal amount of instruments.

(3) Net debt is not a measurement based on 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 are calculated based on sales volumes, net of blending costs.

Operating Results

Our operating results for the second quarter reflect strong drilling results and an increased pace of activity in the Eagle Ford that began late in Q4/2016, the resumption of drilling activity in Canada and a full quarter contribution from the Peace River acquisition, which closed on January 20, 2017.

Production increased 5% to average 72,812 boe/d (79% oil and NGL) in Q2/2017, as compared to 69,298 boe/d (79% oil and NGL) in Q1/2017. Production in the first half of 2017 averaged 71,065 boe/d. During the second quarter, exploration and development capital expenditures totaled $78.0 million, bringing the aggregate spending in the first half of 2017 to $174.6 million. We participated in the drilling of 47 (15.3 net) wells with a 100% success rate during the second quarter.

Reflective of our strong operating results in the first half of the year, we are tightening our 2017 production guidance range to 69,000 to 70,000 boe/d (previously 68,000 to 70,000 boe/d). We are now forecasting full-year 2017 exploration and development capital expenditures of $310 to $330 million (previously $325 to $350 million). We are also reducing our guidance for operating expenses by 4% (at the mid-point) to $10.75-$11.25/boe as we continue to drive cost efficiencies in our business.

We will continue to employ a flexible approach to prudently manage our capital program as we target exploration and development capital expenditures at a level that approximates our funds from operations.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The assets generate the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In Q2/2017, we directed 76% of our exploration and development expenditures toward these assets.

Production increased 7% during the second quarter to average 38,528 boe/d (77% liquids), as compared to 36,081 boe/d in Q1/2017. During the second quarter, we averaged 4-5 drilling rigs and 1-2 completion crews on our lands. In Q2/2017, we participated in the drilling of 38 (9.4 net) wells and commenced production from 35 (8.1 net) wells. At quarter end, we had 51 (13.0 net) wells waiting on completion.

We continue to see strong well performance driven by enhanced completions in the oil window of our acreage with the cost to drill, complete, equip and tie-in a well of US$4.7-4.9 million. The wells that commenced production during the quarter have established 30-day initial gross production rates of approximately 1,500 boe/d per well. Our three recently completed Karnes City pads (total of 11 wells) within the oil window of our Longhorn acreage established 30-day initial gross production rates of approximately 2,150 boe/d per well. These pads were completed with approximately 30 effective frac stages per well and proppant per completed foot of approximately 1,900 pounds, which is more than double the frac intensity of wells previously drilled in the area.

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset for us since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry.

Production increased 8% during the second quarter to average 18,300 boe/d (93% heavy oil), as compared to 17,000 boe/d in Q1/2017. The production increase was driven by an active drilling program combined with a full quarter contribution from the Peace River acquisition, which closed on January 20, 2017.

We drilled 4 (4.0 net) wells during the second quarter and 7 (7.0 net) wells during the first six months of 2017. Six of the wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 400 bbl/d per well and two of these wells ranked among the top oil wells drilled in Alberta during this period.

Lloydminster

Our Lloydminster region, which straddles the Alberta and Saskatchewan border, is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical and horizontal drilling, water flood and steam-assisted gravity drainage operations.

Production averaged approximately 8,600 boe/d (98% heavy oil) during the second quarter, as compared to 9,100 boe/d in Q1/2017. The reduced volumes reflect a lower pace of development activity during the second quarter due to spring break-up. We drilled 5 (1.9 net) wells during the second quarter and 22 (14.9 net) wells during the first six months of 2017.

Financial Review

We generated FFO of $83.1 million ($0.35 per share) in Q2/2017, compared to $81.4 million ($0.35 per share) in Q1/2017. The increase in FFO is largely due to higher production volumes, which more than mitigated the decline in crude oil prices. FFO in the first half of 2017 totaled $164.5 million ($0.70 per share), compared to $126.9 million ($0.60 per share) in the first half of 2016.

Financial Liquidity

We continue to maintain strong financial liquidity as our US$575 million revolving credit facilities are approximately two-thirds undrawn and our first meaningful long-term note maturity is not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our funds from operations, we expect this liquidity position to be stable going forward.

Our revolving credit facilities, which currently mature in June 2019, are covenant-based and do not require annual or semi-annual reviews. We are well within our financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at June 30, 2017 was 0.7:1.0, compared to a maximum permitted ratio of 5.0:1.0, and our interest coverage ratio was 4.0:1.0, compared to a minimum required ratio of 1.25:1.0.

Our net debt totaled $1.8 billion at June 30, 2017, which is down $123 million from June 30, 2016. Our net debt is comprised of over 75% U.S. dollar borrowings and with the recent strengthening of the Canadian dollar relative to the U.S. dollar, we benefit as our net debt expressed in Canadian dollars is reduced. We also benefit from more than half of our operations being based in the U.S. along with approximately 70% of our 2017 exploration and development capital program being invested in the U.S., which mitigates our exposure to fluctuations in the Canada-U.S. dollar exchange rate.

Operating Netback

In Q2/2017, the price for West Texas Intermediate light oil ("WTI") averaged US$48.29/bbl, as compared to US$51.91/bbl in Q1/2017. Offsetting a portion of the decline in WTI was an improved pricing environment for Canadian heavy oil. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$11.13/bbl, as compared to US$14.57/bbl in Q1/2017.

We generated an operating netback in Q2/2017 of $18.30/boe ($18.70/boe including financial derivatives gain), as compared to $19.42/boe ($19.46/boe including financial derivatives gain) in Q1/2017 and $14.39/boe ($18.13/boe including financial derivatives gain) in Q2/2016. The Eagle Ford generated an operating netback of $24.14/boe during Q2/2017 while our Canadian operations generated an operating netback of $11.71/boe.

The following table summarizes our operating netbacks for the periods noted.

	Three Months Ended June 30					
	2017			2016		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**34,284**	**38,528**	**72,812**	31,722	38,309	70,031
Realized sales price	**$ 33.86**	**$ 44.34**	**$ 39.41**	$ 25.80	$ 34.43	$ 30.52
Less:						
Royalty	**4.53**	**13.09**	**9.06**	2.74	9.89	6.65
Operating expense	**14.74**	**7.11**	**10.70**	10.84	6.88	8.67
Transportation expense	**2.88**	**—**	**1.35**	1.78	—	0.81
Operating netback	**$ 11.71**	**$ 24.14**	**$ 18.30**	$ 10.44	$ 17.66	$ 14.39
Realized financial derivatives gain	**—**	**—**	**0.40**	—	—	3.74
Operating netback after financial derivatives gain	**$ 11.71**	**$ 24.14**	**$ 18.70**	$ 10.44	$ 17.66	$ 18.13

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. We realized a financial derivatives gain of $2.6 million in Q2/2017.

For the second half of 2017, we have entered into hedges on approximately 48% of our net WTI exposure with 9% fixed at US$54.46/bbl and 39% hedged utilizing a 3-way option structure that provides us with downside price protection at US$47.17/bbl and upside participation to US$58.60/bbl. We have also entered into hedges on approximately 49% of our net WCS differential exposure at a price differential to WTI of US$13.73/bbl and 68% of our net natural gas exposure through a combination of AECO swaps at C$3.00/mcf and NYMEX swaps at US$2.98/mmbtu.

We are also executing our hedge program for 2018. We have now entered into hedges on approximately 20% of our net WTI exposure with 15% fixed at US$51.28/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$54.40/bbl and upside participation to US$60.00/bbl. We have also entered into hedges on approximately 20% of our net WCS differential exposure at a price differential to WTI of US$14.42/bbl and 19% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.00/mmbtu.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2017 financial statements.

2017 Guidance

The following table summarizes our 2017 annual guidance and compares it to our 2017 year-to-date actual results.

	2017 Guidance			
	Original (1)	**Revised** (2)	**H1/2017**	**Variance**
Exploration and development capital ($ millions)	300 - 350	310 - 330	174.6	N/A
Production (boe/d)	66,000 - 70,000	69,000 - 70,000	71,065	2 %
Expenses:				
Royalty rate (%)	~23.0	~23.0	22.8	(1)%
Operating ($/boe)	11.00 - 12.00	10.75 - 11.25	10.50	(2)%
Transportation ($/boe)	1.10 - 1.30	1.10 - 1.30	1.32	2 %
General and administrative ($/boe) (3)	~2.00	~2.00	2.07	4 %
Interest ($/boe)	~4.00	~4.00	3.97	(1)%

Notes:

(1) Original guidance as announced on December 12, 2016.

(2) On August 1, 2017, we tightened our exploration and development capital and production guidance ranges and reduced our operating expense guidance range by 4% (at the mid-point).

(3) General and administrative expenses in H1/2017 include non-recurring restructuring costs of $0.17/boe associated with staffing reductions. Excluding these restructuring costs, general and administrative expenses were $1.90/boe.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2017 production and capital expenditure guidance; our Eagle Ford assets, including our assessment that it is a premier oil resource play, the cost to drill, complete and equip a well and initial production rates from new wells drilled in Q2/2017; our Peace River assets, including that the area has some of the strongest capital efficiencies in the oil and gas industry and initial production rates from wells drilled in H1/2017; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our target for exploration and development capital expenditures to approximate funds from operations; the effect that a strengthening Canada-U.S. dollar exchange rate will have on our U.S. dollar denominated debt; that our U.S. operations mitigate our exposure to fluctuations in the Canada-U.S. dollar exchange rate; our ability to partially reduce the volatility in our funds from operations by utilizing financial derivative contracts for commodity prices, heavy oil differentials and interest and foreign exchange rates; the percentage of our anticipated 2017 and 2018 oil and natural gas production that is hedged; and our expected royalty rate and per boe operating, transportation, general and administrative and interest costs for 2017. 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.

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.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial Measures

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. 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.

Advisory Regarding Oil and Gas Information

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2017. This information is provided as of July 31, 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 three and six months ended June 30, 2017 ("Q2/2017" and "YTD 2017") have been compared with the results for the three and six months ended June 30, 2016 ("Q2/2016" and "YTD 2016"). This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and six months ended June 30, 2017, its audited comparative consolidated financial statements for the years ended December 31, 2016 and 2015, together with the accompanying notes, and its 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, per common share amounts or as otherwise noted.

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

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

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by GAAP. While funds from operations, net debt, operating netback and Bank 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.

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 investment, debt repayment and potential future dividends. We believe that this measure provides a meaningful assessment of our operations by eliminating certain non-cash charges. However, FFO 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 FFO.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Cash flow from operating activities	**$ 70,241**	$ 54,961	**$ 150,973**	$ 119,314
Change in non-cash working capital	**10,427**	25,592	**5,637**	5,183
Asset retirement expenditures	**2,468**	708	**7,895**	2,409
Funds from operations	**$ 83,136**	$ 81,261	**$ 164,505**	$ 126,906

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)		**June 30, 2017**		December 31, 2016
Bank loan[1]	**$**	**264,032**	$	191,286
Long-term notes[1]		**1,541,694**		1,584,158
Working capital deficiency (surplus)[2]		**13,661**		(1,903)
Net debt	**$**	**1,819,387**	$	1,773,541

(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).

Operating Netback

We define operating netback as petroleum and natural gas sales, less blending expense, 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. Our heavy oil operations require us to purchase diluent for blending that is recovered in the sales price of the blended product. Our purchases and sales of blending diluent are recorded as heavy oil blending expense and sales. We reduce the petroleum and natural gas sales by the blending expense in order to calculate our heavy oil sales to compare our realized price to the benchmark price.

	Three Months Ended June 30				Six Months Ended June 30			
($ thousands)		**2017**		2016		**2017**		2016
Petroleum and natural gas sales	**$**	**274,369**	$	195,733	**$**	**534,918**	$	349,331
Less: Blending expense		**(13,260)**		(1,207)		**(23,317)**		(3,566)
Petroleum and natural gas sales, net of blending expense		**261,109**		194,526		**511,601**		345,765
Royalties		**60,014**		42,386		**117,191**		76,968
Operating expense		**70,925**		55,275		**135,055**		124,955
Transportation expense		**8,973**		5,146		**17,015**		11,921
Operating netback		**121,197**		91,719		**242,340**		131,921
Realized financial derivatives gain		**2,649**		23,816		**2,923**		68,442
Operating netback after realized financial derivatives gain	**$**	**123,846**	$	115,535	**$**	**245,263**	$	200,363

Bank EBITDA

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Net income (loss)	**$ 9,268**	$ (86,937)	**$ 20,364**	$ (86,330)
Plus:				
Financing and interest	**29,293**	27,888	**57,799**	56,941
Unrealized foreign exchange (gain) loss	**(32,045)**	3,549	**(43,383)**	(83,252)
Unrealized financial derivatives (gain) loss	**(13,229)**	80,564	**(48,843)**	110,687
Current income tax recovery	**(705)**	(2,284)	**(1,441)**	(3,726)
Deferred income tax recovery	**(23,295)**	(46,783)	**(35,740)**	(94,905)
Depletion and depreciation	**131,155**	121,940	**253,486**	263,611
Loss on disposition of oil and gas properties	**524**	—	**524**	22
Non-cash items[1]	**9,279**	5,829	**15,150**	11,732
Bank EBITDA	**$ 110,245**	$ 103,766	**$ 217,916**	$ 174,780

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

SECOND QUARTER HIGHLIGHTS

Baytex achieved strong operating and financial results for Q2/2017. Production increased 5% from Q1/2017 and 12% from Q4/2016 and averaged 72,812 boe/d in the quarter. We generated funds from operations of $83.1 million while investing $78.0 million on exploration and development capital expenditures. YTD 2017 production averaged 71,065 boe/d, generating funds from operations of $164.5 million while spending $174.6 million on exploration and development. As a result of our strong operating results in the first half of 2017, we are tightening our 2017 production guidance range to 69,000 to 70,000 boe/d (previously 68,000 to 70,000 boe/d).

In Canada, our exploration and development activities were focused on our Peace River and Lloydminster properties. At Peace River, we drilled 4 (4.0 net) wells during Q2/2017 and 7 (7.0 net) wells during YTD 2017. In Lloydminster, our pace of development was slowed in Q2/2017 due to spring break up and we drilled 5 (1.9 net) wells during Q2/2017 and have drilled 22 (14.9 net) wells during the first six months of 2017. We have had strong drilling results in both Peace River and Lloydminster during the first half of 2017 after having limited activity on these lands in 2015 and 2016. Production averaged 34,284 boe/d for Q2/2017, an increase of 3% from 33,217 boe/d for Q1/2017 and an increase of 8% from 31,704 boe/d in Q4/2016. We closed the Peace River asset acquisition on January 20, 2017 and were able to reactivate a portion of wells associated with the acquisition during the period which contributed to the increase in production.

In the U.S., we increased our rig activity at the end of 2016 and kept this pace of development through Q2/2017, averaging 4-5 drilling rigs and 1-2 completion crew on our lands, resulting in 38 (9.4 net) wells drilled in Q2/2017 and 74 (17.8 net) wells drilled in YTD 2017. Exploration and development capital was $59.6 million for Q2/2017 and $117.6 million for YTD 2017. Production was 38,528 boe/d for Q2/2017, up 7% from 36,081 boe/d in Q1/2017 and up 15% from 33,432 in Q4/2016. The increased pace of development combined with strong 2017 well results related to completion programs with increased frac stages and higher proppant usage contributed to the increase in production from Q4/2016.

Total production of 72,812 boe/d for Q2/2017 is up 5% from 69,298 boe/d for Q1/2017 and up 4% from 70,031 boe/d for Q2/2016. Total production of 71,065 boe/d for the first six months of 2017 exceeded our revised annual guidance of 69,000 - 70,000 boe/d. Strong well results in the Eagle Ford and initial new well production from our Canadian capital program, combined with reactivations on the acquired Peace River properties, contributed to higher Q2/2017 production.

During Q2/2017, the ongoing efforts of the Organization of the Petroleum Exporting Countries ("OPEC") to balance the oil market with production curtailments was met with concern over rising non-OPEC production and elevated inventory levels which resulted in a decline in the WTI benchmark price for Q2/2017 relative to Q1/2017. Despite these recent declines, WTI averaged US$48.28/bbl for Q2/2017, an increase of 6% from US$45.60/bbl for the same period of 2016. Natural gas prices also increased compared to Q2/2016, with AECO increasing 122% to $2.77/mcf for Q2/2017 from $1.25/mcf for Q2/2016 and NYMEX increasing 63% to US$3.18/mmbtu for Q2/2017 from US$1.95/mmbtu for Q2/2016. The improvement in commodity prices during Q2/2017 increased our realized sales price to $39.41/boe from $30.52/boe in Q2/2016.

We generated FFO of $83.1 million for Q2/2017 which is up $1.8 million from $81.3 million in Q2/2016 and also up $1.7 million from the $81.4 million generated in Q1/2017. Higher realized prices combined with higher production account for the increase in Q2/2017 compared to Q2/2016 whereas the increased production in Q2/2017 from Q1/2017 more than offset the recent pullback in commodity prices explaining the increase in FFO from Q1/2017.

As at June 30, 2017, our net debt was $1.82 billion, as compared to $1.77 billion at December 31, 2016. The increase is mainly due to the Peace River acquisition which closed January 20, 2017 and was pre-funded with the $115 million equity issuance in December 2016. At June 30, 2017, we were in compliance with all of our financial covenants and had approximately $470 million of undrawn credit capacity. For 2017, we will continue to employ a flexible approach to prudently manage our capital program as we target exploration and development capital expenditures at a level that approximates FFO.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended June 30					
	2017			2016		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**25,577**	**—**	**25,577**	22,423	—	22,423
Light oil and condensate	**1,258**	**21,112**	**22,370**	1,461	20,433	21,894
NGL	**964**	**8,729**	**9,693**	1,268	8,566	9,834
Total liquids (bbl/d)	**27,799**	**29,841**	**57,640**	25,152	28,999	54,151
Natural gas (mcf/d)	**38,908**	**52,120**	**91,028**	39,422	55,859	95,281
Total production (boe/d)	**34,284**	**38,528**	**72,812**	31,722	38,309	70,031
Production Mix						
Heavy oil	**75%**	**—%**	**35%**	71%	—%	32%
Light oil and condensate	**4%**	**55%**	**31%**	5%	54%	31%
NGL	**3%**	**23%**	**13%**	4%	22%	14%
Natural gas	**18%**	**22%**	**21%**	20%	24%	23%

	Six Months Ended June 30					
	2017			2016		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**25,104**	**—**	**25,104**	23,615	—	23,615
Light oil and condensate	**1,255**	**20,741**	**21,996**	1,513	21,678	23,191
NGL	**1,031**	**7,972**	**9,003**	1,301	8,670	9,971
Total liquids (bbl/d)	**27,390**	**28,713**	**56,103**	26,429	30,348	56,777
Natural gas (mcf/d)	**38,181**	**51,590**	**89,771**	40,712	56,038	96,750
Total production (boe/d)	**33,754**	**37,311**	**71,065**	33,214	39,688	72,902
Production Mix						
Heavy oil	**74 %**	**— %**	**35 %**	71 %	— %	32 %
Light oil and condensate	**4 %**	**56 %**	**31 %**	5 %	55 %	32 %
NGL	**3 %**	**21 %**	**13 %**	4 %	22 %	14 %
Natural gas	**19 %**	**23 %**	**21 %**	20 %	23 %	22 %

We reported average daily production of 72,812 boe/d for Q2/2017, up 5% from Q1/2017 production of 69,298 boe/d and up 4% from Q2/2016. The increase in production reflects our successful capital programs in Canada and the U.S. which more than offset the impact of natural declines from lower capital activity throughout 2016.

In Canada, daily production for Q2/2017 was 34,284 boe/d, an increase of 3% from 33,217 boe/d for Q1/2017 and an increase of 8% from 31,722 boe/d reported for Q2/2016. We reported positive initial production results from operated wells in Peace River brought online during the second quarter. New production from these wells along with production from the Peace River acquisition, which closed on January 20, 2017, resulted in an increase in Canadian production from Q1/2017. During Q2/2016, certain high cost heavy oil production was shut-in which reduced averaged daily production for the period by approximately 4,250 boe/d. Reactivation of this production combined with our successful 2017 capital program and the Peace River acquisition resulted in an 8% increase in Canadian production for Q2/2017 compared to Q2/2016.

Daily production in the U.S. was 38,528 boe/d for Q2/2017, up 7% from 36,081 boe/d in Q1/2017 and up 1% from 38,309 boe/d for Q2/2016. We remained active during the second quarter with an average of 4-5 drilling rigs and 1-2 completion crews on our lands. Enhanced completion techniques resulted in better than anticipated well performance and contributed to the production increase of 2,447 boe/d from Q1/2017. Strong well performance and our active U.S. capital program more than offset 1,000 boe/d of production lost with the Q3/2016 disposition of our operated Eagle Ford properties, resulting in slightly higher average daily production in Q2/2017 as compared to Q2/2016.

Our average daily production for the first six months of 2017 was 71,065 boe/d compared to 72,902 boe/d reported for the same period of 2016. Strong well performance in the U.S. and Canada resulted in reported production exceeding the high end of our revised annual guidance range of 69,000 - 70,000 boe/d. This new production combined with the reactivation of shut-in heavy oil production and the Q1/2017 Peace River acquisition nearly offset the effect of the disposition of our operated Eagle Ford assets and natural declines from a less active 2016 capital program. As a result, average daily production for the six months ended June 30, 2017 was 3% or 1,837 boe/d lower than the comparative period of 2016.

Commodity Prices

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

Crude Oil

Global oil prices declined during Q2/2017 as concerns over rising non-OPEC production and elevated inventory levels overshadowed OPEC's attempt to balance the market. Despite these recent declines, oil prices were higher during the first six months of 2017 relative to multi-year lows for the first six months of 2016. The West Texas Intermediate light oil ("WTI") benchmark averaged US$48.28/bbl for Q2/2017 and US$50.10/bbl for the six months ended June 30, 2017. This compares to an average of US$45.60/bbl for Q2/2016 and US$39.53/bbl for the first six months of 2016.

Our U.S. crude oil price is primarily referenced to the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is the representative benchmark for light oil pricing at the U.S. Gulf coast. The LLS benchmark was US$49.70/bbl for Q2/2017, up 8% compared to an average of US$46.20/bbl for Q2/2016 and down 5% from US$52.50/bbl for the first quarter of 2017.

The price received for our heavy oil sales in Canada is based on the Western Canadian Select ("WCS") price, which trades at a discount or differential to WTI. For Q2/2017, the WCS heavy oil differential averaged US$11.12/bbl, as compared to US$13.31/bbl for Q2/2016 and US$14.58/bbl for Q1/2017. The WCS differential was lower during Q2/2017 due to Canadian production turnarounds and third-party facility downtime which lowered supply combined with increased downstream demand caused by less downtime for U.S. refinery turnarounds relative to previous years.

Natural Gas

Natural gas prices were higher during the first half of 2017 relative to the same period in 2016. Higher demand due to increased exports to Mexico and increasing North American liquefied natural gas sales have resulted in lower storage levels and improved North American market pricing.

We compare our realized price on U.S. natural gas production to the New York Mercantile Exchange ("NYMEX") natural gas index. During Q2/2017, the NYMEX natural gas benchmark averaged US$3.18/mmbtu, an increase of 63% from US$1.95/mmbtu for the same period of 2016 and a slight decrease from Q1/2017 when the benchmark averaged US$3.32/mmbtu.

In Canada, we receive natural gas pricing based on the AECO benchmark which averaged $2.77/mcf during Q2/2017. This represents an increase of 122% compared to $1.25/mcf in Q2/2016 and a decrease of 6% from $2.94/mcf for Q1/2017. AECO continues to trade at a significant discount to NYMEX due to continued oversupply and pipeline constraints in Western Canada.

The following tables compare selected benchmark prices and our average realized selling prices for the three and six months ended June 30, 2017 and 2016.

	Three Months Ended June 30			Six Months Ended June 30		
	2017	2016	Change	**2017**	2016	Change
Benchmark Averages						
WTI oil (US$/bbl)(1)	**48.28**	45.60	6 %	**50.10**	39.53	27%
WTI oil (CAD$/bbl)	**64.93**	58.76	11 %	**66.82**	52.64	27%
WCS heavy oil (US$/bbl)(2)	**37.16**	32.29	15 %	**37.25**	25.76	45%
WCS heavy oil (CAD$/bbl)	**49.97**	41.61	20 %	**49.68**	34.31	45%
LLS oil (US$/bbl)(3)	**49.70**	46.20	8 %	**51.10**	39.73	29%
LLS oil (CAD$/bbl)	**66.83**	59.53	12 %	**68.15**	52.91	29%
CAD/USD average exchange rate	**1.3447**	1.2885	4 %	**1.3338**	1.3317	—%
Edmonton par oil ($/bbl)	**61.92**	54.78	13 %	**62.95**	47.80	32%
AECO natural gas price ($/mcf)(4)	**2.77**	1.25	122 %	**2.86**	1.68	70%
NYMEX natural gas price (US$/mmbtu)(5)	**3.18**	1.95	63 %	**3.25**	2.02	61%

(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 monthly average index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended June 30					
	2017			2016		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Canadian heavy oil ($/bbl)(2)	**$ 37.62**	**$ —**	**$ 37.62**	$ 30.09	$ —	$ 30.09
Light oil and condensate ($/bbl)	**54.07**	**61.07**	**60.68**	47.24	52.79	52.42
NGL ($/bbl)	**28.17**	**22.10**	**22.70**	18.56	12.50	13.28
Natural gas ($/mcf)	**2.66**	**4.34**	**3.62**	1.30	2.39	1.94
Weighted average ($/boe)(2)	**$ 33.86**	**$ 44.34**	**$ 39.41**	$ 25.80	$ 34.43	$ 30.52

	Six Months Ended June 30					
	2017			2016		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Canadian heavy oil ($/bbl)(2)	**$ 36.81**	**$ —**	**$ 36.81**	$ 20.87	$ —	$ 20.87
Light oil and condensate ($/bbl)	**56.04**	**62.30**	**61.94**	41.37	45.03	44.79
NGL ($/bbl)	**29.17**	**23.76**	**24.38**	17.72	15.59	15.86
Natural gas ($/mcf)	**2.65**	**4.25**	**3.57**	1.62	2.57	2.17
Weighted average ($/boe)(2)	**$ 33.35**	**$ 45.59**	**$ 39.77**	$ 19.40	$ 31.63	$ 26.06

(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 but does include physical contracts settled during the period.
(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

Average Realized Sales Prices

For Q2/2017, our weighted average sales price was $39.41/boe, up $8.89/boe from $30.52/boe for Q2/2016 reflecting the improved benchmark pricing received for our sales volumes during Q2/2017 relative to Q2/2016.

In Canada, our average realized heavy oil sales price was $37.62/bbl for Q2/2017 was up $7.53/bbl compared to $30.09/bbl for the same period of 2016. The increase in realized heavy oil sales pricing for Q2/2017 is primarily a result of the increase in WCS benchmark pricing (expressed in Canadian dollars) which was up $8.36/bbl relative to Q2/2016.

Our realized Canadian light oil and condensate price averaged $54.07/bbl for Q2/2017, an increase of 14% from $47.24/bbl for Q2/2016. The price received for Canadian light oil and condensate sales is discounted to benchmark oil prices with adjustments for quality and is net of fees and differentials that do not fluctuate with prices. The increase in realized light oil and condensate pricing relative to Q2/2016 is consistent with a 13% increase in Edmonton par pricing.

In the U.S., our realized light oil and condensate price was $61.07/bbl for the three months ended June 30, 2017. This was up 16% from $52.79/bbl for Q2/2016 compared to a 12% increase in the LLS benchmark (expressed in Canadian dollars) over the same period. Reduced supply along with increased pipeline capacity has tightened the pricing differential on our U.S. light oil and condensate realized price relative to the LLS benchmark combined with a weaker Canadian dollar in Q2/2017 which resulted in an increase to the LLS benchmark expressed in Canadian dollars and our realized pricing relative to the same period of 2016.

The increase in our realized Canadian natural gas sales price for Q2/2017 reflects the 122% increase in the AECO benchmark pricing relative to Q2/2016. Our realized natural gas sales price in Canada was $2.66/mcf for Q2/2017 representing an increase of 105% or $1.36/mcf from Q2/2016 when our realized price averaged $1.30/mcf.

Our U.S. realized natural gas price was $4.34/mcf for Q2/2017, up $1.95/mcf or 82% from Q2/2016. This is comparable to an increase in the NYMEX benchmark (expressed in Canadian dollars) of $1.76/mmbtu or 70% over the same period.

For Q2/2017, our realized NGL price was $22.70/bbl or 35% of WTI (expressed in Canadian dollars) compared to $13.28/bbl or 23% of WTI in Q2/2016. Our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products.

Our weighted average sales price was $39.77/boe for the first six months of 2017, up 53% from $26.06/boe reported for the same period of 2016. Increases in Canadian and U.S. benchmark prices resulted in higher realized prices received for our heavy oil, light oil and condensate, NGL and natural gas sales relative to the same period of 2016.

Petroleum and Natural Gas Sales

	Three Months Ended June 30					
	2017			2016		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil[1]	**$ 100,829**	**$ —**	**$ 100,829**	$ 62,603	$ —	$ 62,603
Light oil and condensate	**6,189**	**117,335**	**123,524**	6,279	98,162	104,441
NGL	**2,472**	**17,555**	**20,027**	2,141	9,744	11,885
Total liquids sales	**109,490**	**134,890**	**244,380**	71,023	107,906	178,929
Natural gas sales	**9,406**	**20,583**	**29,989**	4,673	12,131	16,804
Petroleum and natural gas sales	**$ 118,896**	**$ 155,473**	**$ 274,369**	$ 75,696	$ 120,037	$ 195,733

	Six Months Ended June 30					
	2017			2016		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil[1]	**$ 190,580**	**$ —**	**$ 190,580**	$ 93,269	$ —	$ 93,269
Light oil and condensate	**12,726**	**233,869**	**246,595**	11,393	177,667	189,060
NGL	**5,444**	**34,279**	**39,723**	4,196	24,593	28,789
Total liquids sales	**208,750**	**268,148**	**476,898**	108,858	202,260	311,118
Natural gas sales	**18,297**	**39,723**	**58,020**	11,986	26,227	38,213
Petroleum and natural gas sales	**$ 227,047**	**$ 307,871**	**$ 534,918**	$ 120,844	$ 228,487	$ 349,331

(1) 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. Heavy oil revenue includes heavy oil blending revenue.

Total petroleum and natural gas sales for Q2/2017 of $274.4 million increased $78.7 million or 40% from $195.7 million reported for the same period of 2016. The increase was driven by higher average daily production in Canada and the U.S. combined with a 29% increase in our weighted averaged realized price relative to Q2/2016.

In Canada, petroleum and natural gas sales were $118.9 million for Q2/2017, up 57% from $75.7 million for Q2/2016. Our weighted average realized price in Canada increased 31% from $25.80/boe in Q2/2016 to $33.86/boe for Q2/2017. This increase is primarily due to the increase in benchmark prices along with an increase in heavy oil blending revenue associated with the acquisition of the Peace River assets on January 20, 2017 combined with an increase in blending activity at our Lloydminster properties. Positive well results from our Canadian capital program, combined with production from the acquired properties and re-activated production, resulted in a 2,562 boe/d increase in total average daily production as compared to Q2/2016.

Petroleum and natural gas sales of $155.5 million in the U.S. increased 30% or $35.5 million from $120.0 million reported for Q2/2016. Strong well performance and improved completion techniques offset the impact of dispositions and natural declines, resulting in a slight increase in average daily production compared to Q2/2016. Higher benchmark prices and a weaker Canadian dollar resulted in a 29% increase in our weighted average realized price of $44.34/boe for Q2/2017.

We reported total petroleum and natural gas sales of $534.9 million for the first six months of 2017, representing an increase of 53% or $185.6 million compared to $349.3 million for the first six months of 2016. Our realized price for the six months ended June 30, 2017 increased 53% relative to the same period of 2016, resulting in a $202.5 million increase in total petroleum and natural gas sales. This was offset by a 3% decrease in production which lowered total petroleum and natural gas sales for the period by $16.9 million.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2017 and 2016.

	Three Months Ended June 30					
	2017			2016		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 14,119**	**$ 45,895**	**$ 60,014**	$ 7,920	$ 34,466	$ 42,386
Average royalty rate[1]	**13.2%**	**29.5%**	**22.9%**	10.6%	28.7%	21.8%
Royalty rate per boe	**$ 4.53**	**$ 13.09**	**$ 9.06**	$ 2.74	$ 9.89	$ 6.65

	Six Months Ended June 30					
	2017			2016		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 26,752**	**$ 90,439**	**$ 117,191**	$ 11,755	$ 65,213	$ 76,968
Average royalty rate[1]	**13.1%**	**29.4%**	**22.8%**	10.0%	28.5%	22.3%
Royalty rate per boe	**$ 4.38**	**$ 13.39**	**$ 9.11**	$ 1.94	$ 9.03	$ 5.80

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

Total royalties for Q2/2017 were $60.0 million and averaged 22.9% of oil and natural gas revenues. Our Canadian royalty rate, which varies with price, increased to 13.2% of oil and natural gas revenues for Q2/2017 compared to 10.6% in Q2/2016, primarily due to higher commodity prices. The royalty rate on our U.S. production does not vary with price and, as a result, the Q2/2017 U.S. royalty rate of 29.5% has remained fairly consistent with the Q2/2016 rate of 28.7%. The increase in our Canadian royalty rate combined with higher petroleum and natural gas sales resulted in total royalties of $60.0 million for Q2/2017, an increase of $17.6 million from Q2/2016.

Royalties for the six months ended June 30, 2017 were $117.2 million and averaged 22.8% of oil and natural gas revenues which was in line with our annual guidance of approximately 23% of revenue. The royalty rate in Canada averaged 13.1% of oil and natural gas revenues for the first half of 2017, an increase from 10.0% for the same period of 2016 as a result of higher commodity prices. In the U.S., royalties for the first half of 2017 averaged 29.4% of revenues which is fairly consistent with 28.5% for the same period in 2016 as the royalty rate on our U.S. production does not vary with price but can vary slightly across our acreage. Total royalties of $117.2 million for the first half of 2017 increased $40.2 million from the same period of 2016 as a result of higher realized pricing in combination with an increase in our Canadian royalty rate.

Operating Expense

	Three Months Ended June 30					
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Operating expense	**$ 45,981**	**$ 24,944**	**$ 70,925**	$ 31,280	$ 23,995	$ 55,275
Operating expense per boe	**$ 14.74**	**$ 7.11**	**$ 10.70**	$ 10.84	$ 6.88	$ 8.67

Six Months Ended June 30	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expense	**$ 89,384**	**$ 45,671**	**$ 135,055**	$ 65,925	$ 59,030	$ 124,955
Operating expense per boe	**$ 14.63**	**$ 6.76**	**$ 10.50**	$ 10.91	$ 8.17	$ 9.42

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

Total operating expense was $70.9 million ($10.70/boe) for Q2/2017 as compared to $55.3 million ($8.67/boe) for Q2/2016. We continue to drive cost efficiencies in our business and have reduced our 2017 guidance for operating expenses to $10.75-$11.25/boe. Per unit operating expense for Q2/2017 is below this range as production for the period was above the high end of our annual guidance range. The increase in total per unit costs relative to Q2/2016 is a result of the Peace River acquisition in Q1/2017, a weaker CAD/USD exchange rate and high cost properties being shut-in for a portion of the comparative period in 2016.

In Canada, operating expense increased to $46.0 million ($14.74/boe) in Q2/2017 from $31.3 million ($10.84/boe) in Q2/2016. We anticipated an increase to Canadian operating costs following the Q1/2017 acquisition of Peace River properties which have higher per boe operating costs than our other properties. Canadian operating costs also increased with the re-activation of higher cost production which was shut-in for a portion of the comparative period in 2016.

U.S. operating expense of $24.9 million ($7.11/boe) for Q2/2017 increased from $24.0 million ($6.88/boe) for the same period of 2016. The increase is primarily a result of a weakening of the CAD/USD exchange rate. On a USD basis, operating costs actually decreased to US$5.29/boe in Q2/2017 compared to US$5.35/boe in Q2/2016. The decrease can be attributed to the disposition of our operated U.S. properties in Q3/2016 which had higher operating costs.

Operating expense for the six months ended June 30, 2017 was $135.1 million ($10.50/boe) compared to $125.0 million ($9.42/boe) for the same period of 2016. Per unit operating costs for the first half of 2017 were below our annual guidance range of $10.75/boe to $11.25/boe as production for the period exceeded the high end of our annual guidance range and we began to realize benefits from our cost savings initiatives.

Canadian operating expense was $89.4 million ($14.63/boe) for the first half of 2017 which is $23.5 million higher than the first half of 2016. The increase reflects the reactivation of higher cost production that was shut-in for a portion of the comparative period in 2016 along with the Q1/2017 acquisition of higher operating cost properties in Peace River.

In the U.S., operating expense was $45.7 million ($6.76/boe) for the six months ended June 30, 2017 compared to $59.0 million ($8.17/boe) for the same period of 2016. The Q3/2016 disposition of the Company's operated U.S. properties, which had higher per unit operating costs, combined with a general reduction in costs on our non-operated properties, resulted in the decrease in U.S. operating expense in 2017 compared to the first six months 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 three and six months ended June 30, 2017 and 2016.

Three Months Ended June 30	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expense	**$ 8,973**	**$ —**	**$ 8,973**	$ 5,146	$ —	$ 5,146
Transportation expense per boe	**$ 2.88**	**$ —**	**$ 1.35**	$ 1.78	$ —	$ 0.81

Six Months Ended June 30	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expense	**$ 17,015**	**$ —**	**$ 17,015**	$ 11,921	$ —	$ 11,921
Transportation expense per boe	**$ 2.79**	**$ —**	**$ 1.32**	$ 1.97	$ —	$ 0.90

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

Transportation expense was $9.0 million ($1.35/boe) for Q2/2017 and $17.0 million ($1.32/boe) for the six months ended June 30, 2017, up from $5.1 million ($0.81/boe) and $11.9 million ($0.90/boe) reported for the three and six month periods of 2016, respectively. The increase in transportation expense during 2017 relative to 2016 was caused by the Q1/2017 Peace River property acquisition which increased trucking volumes and distances combined with wet weather during Q2/2017. As a result, our transportation expense for Q2/2017 and YTD 2017 was slightly above our annual guidance range of $1.10/boe to $1.30/boe.

Blending Expense

Our heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. We purchase blending diluent to reduce the viscosity and record a blending expense. The blending diluent is recovered in the sale of heavy oil. Our heavy oil blending revenue and expense is net against our heavy oil sales in order to compare our realized heavy oil sales price to benchmark pricing.

Blending expense was $13.3 million for Q2/2017 and $23.3 million for the first six months of 2017 representing increases of $12.1 million and $19.8 million, respectively, from the comparative three and six month periods in 2016. Blending expenses have increased during 2017 due to additional blending diluent purchases for the acquired Peace River properties combined with higher diluent prices relative to 2016. The increase is also a result of higher pipeline blending activities at our Lloydminster properties during 2017 as a third party pipeline outage impacted these activities during the majority of the 2016 comparative periods.

Financial Derivatives

As part of our normal operations, we are exposed to fluctuations in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and six months ended June 30, 2017 and 2016.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2017**	2016	Change	**2017**	2016	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 2,772**	$ 18,778	$ (16,006)	**$ 3,856**	$ 60,270	$ (56,414)
Natural gas	**(123)**	5,038	(5,161)	**(933)**	8,172	(9,105)
Total	**$ 2,649**	$ 23,816	$ (21,167)	**$ 2,923**	$ 68,442	$ (65,519)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 9,958**	$ (64,539)	$ 74,497	**$ 35,848**	$ (99,526)	$ 135,374
Natural gas	**3,271**	(16,025)	19,296	**12,995**	(11,161)	24,156
Total	**$ 13,229**	$ (80,564)	$ 93,793	**$ 48,843**	$ (110,687)	$ 159,530
Total financial derivatives gain (loss)						
Crude oil	**$ 12,730**	$ (45,761)	$ 58,491	**$ 39,704**	$ (39,256)	$ 78,960
Natural gas	**3,148**	(10,987)	14,135	**12,062**	(2,989)	15,051
Total	**$ 15,878**	$ (56,748)	$ 72,626	**$ 51,766**	$ (42,245)	$ 94,011

We recorded a realized gain on financial derivatives of $2.6 million for Q2/2017 compared to a realized gain on financial derivatives of $23.8 million for Q2/2016. The realized gain on financial derivatives was $2.9 million for the first six months of 2017 compared to $68.4 million for the same period of 2016.

Realized gains on crude oil financial derivatives were a result of a decline in the WTI index during the period relative to our fixed contract prices. For Q2/2017, we had 3,500 bbl/d of fixed sell contracts at a weighted averaged price of US$54.46/bbl compared to the average WTI index of US$48.28/bbl for the period. During May and June of 2017, the WTI index averaged US$48.54/bbl and US$45.20/bbl, respectively, which was below the purchased put price of US$50.00/bbl on 6,500 bbl/d of our three way options. Gains on these WTI financial derivatives were partially offset by losses on our WCS basis swap contracts with a weighted averaged fixed price of WTI less US$13.49/bbl relative to the WCS to WTI differential of US$11.12/bbl for Q2/2017.

The unrealized financial derivatives gain of $13.2 million for Q2/2017 is mainly due to a decrease in commodity price futures at June 30, 2017 as compared to March 31, 2017. At June 30, 2017, the fair value of our financial derivative contracts represent a net asset of $19.7 million compared to a net asset of $6.5 million at March 31, 2017 and a net liability of $29.1 million at December 31, 2016.

Baytex had the following financial derivative contracts outstanding as of July 31, 2017.

	Remaining Term	Volume	Price/Unit [1]	Index
Oil				
Basis swap	Jul 2017 to Sep 2017	6,000 bbl/d	WTI less US$13.53/bbl	WCS
Basis swap	Jul 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42/bbl	WCS
Basis swap	Oct 2017 to Dec 2017	4,000 bbl/d	WTI less US$13.06/bbl	WCS
Basis swap	Jan 2018 to Jun 2018	2,000 bbl/d	WTI less US$14.23/bbl	WCS
Basis swap	Jan 2018 to Dec 2018	3,000 bbl/d	WTI less US$14.48/bbl	WCS
Fixed - sell	Jul 2017 to Dec 2017	3,500 bbl/d	US$54.46/bbl	WTI
3-way option [2]	Jul 2017 to Dec 2017	14,500 bbl/d	US$58.61/US$47.17/US$37.24	WTI
3-way option [2]	Jan 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Swaption [3]	Jan 2018 to Dec 2018	1,000 bbl/d	US$54.00/bbl	WTI
Swaption [3]	Jan 2018 to Dec 2018	1,000 bbl/d	US$50.00/bbl	WTI
Swaption [3]	Jan 2018 to Dec 2018	1,500 bbl/d	US$51.00/bbl	WTI
Swaption [3]	Jan 2018 to Dec 2018	1,000 bbl/d	US$50.10/bbl	WTI
Swaption [3]	Jan 2018 to Dec 2018	500 bbl/d	US$50.90/bbl	WTI
Swaption [3]	Jan 2018 to Dec 2018	500 bbl/d	US$52.00/bbl	WTI
Natural Gas				
Fixed - sell	Jul 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO
Fixed - sell	Jul 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 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) For these contracts, Baytex received a higher swap price in exchange for writing a call option whereby the holder has the right, if exercised on December 29, 2017, to enter an additional swap transaction for the same remaining term, notional volume and fixed price per unit.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and six months ended June 30, 2017 and 2016.

	Three Months Ended June 30					
	2017			2016		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**34,284**	**38,528**	**72,812**	31,722	38,309	70,031
Operating netback:						
Realized sales price	**$ 33.86**	**$ 44.34**	**$ 39.41**	$ 25.80	$ 34.43	$ 30.52
Less:						
Royalty	**4.53**	**13.09**	**9.06**	2.74	9.89	6.65
Operating expense	**14.74**	**7.11**	**10.70**	10.84	6.88	8.67
Transportation expense	**2.88**	**—**	**1.35**	1.78	—	0.81
Operating netback	**$ 11.71**	**$ 24.14**	**$ 18.30**	$ 10.44	$ 17.66	$ 14.39
Realized financial derivatives gain	**—**	**—**	**0.40**	—	—	3.74
Operating netback after financial derivatives gain	**$ 11.71**	**$ 24.14**	**$ 18.70**	$ 10.44	$ 17.66	$ 18.13

Six Months Ended June 30						
	2017			2016		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**33,754**	**37,311**	**71,065**	33,214	39,688	72,902
Operating netback:						
Realized sales price	**$ 33.35**	**$ 45.59**	**$ 39.77**	$ 19.40	$ 31.63	$ 26.06
Less:						
Royalty	**4.38**	**13.39**	**9.11**	1.94	9.03	5.80
Operating expense	**14.63**	**6.76**	**10.50**	10.91	8.17	9.42
Transportation expense	**2.79**	**—**	**1.32**	1.97	—	0.90
Operating netback	**$ 11.55**	**$ 25.44**	**$ 18.84**	$ 4.58	$ 14.43	$ 9.94
Realized financial derivatives gain	**—**	**—**	**0.23**	—	—	5.16
Operating netback after financial derivatives gain	**$ 11.55**	**$ 25.44**	**$ 19.07**	$ 4.58	$ 14.43	$ 15.10

We reported a 27% increase in operating netbacks of $18.30/boe for Q2/2017, compared to $14.39/boe for the same period of 2016. Our YTD 2017 operating netback increased 90% or $8.90/boe to $18.84/boe from $9.94/boe in YTD 2016. The increase in our realized sales price per boe during 2017 was offset by higher per unit royalties, operating and transportation expenses compared to the same periods of 2016. Higher per boe operating and transportation expenses in the current periods were driven by the re-activation of higher operating cost properties which were shut-in for a portion of the comparative period in 2016 combined with the Q1/2017 Peace River acquisition, which has higher per unit operating and transportation expenses than our other properties. Realized gains on financial derivatives were lower in 2017 as index pricing for the period was higher relative to the price set in our fixed price contracts as compared to 2016.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of lease expiries, the accumulated costs of expiring leases, and the economic facts and circumstances related to the Company's exploration programs.

E&E expense of $3.7 million for Q2/2017 includes $2.3 million of costs associated with the derecognition of the accumulated carrying amount for exploration programs that we determined were not viable. As a result, we recorded $5.0 million of E&E expense for the first six months of 2017 which is higher than $3.4 million recorded for the same period in 2016.

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes, and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and six months ended June 30, 2017 and 2016.

Three Months Ended June 30						
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation(1)	**$ 52,034**	**$ 78,617**	**$ 131,155**	$ 46,843	$ 74,470	$ 121,940
Depletion and depreciation per boe	**$ 16.68**	**$ 22.42**	**$ 19.79**	$ 16.23	$ 21.36	$ 19.13

Six Months Ended June 30						
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation(1)	**$ 101,865**	**$ 149,970**	**$ 253,486**	$ 101,628	$ 160,609	$ 263,611
Depletion and depreciation per boe	**$ 16.67**	**$ 22.21**	**$ 19.71**	$ 16.81	$ 22.24	$ 19.87

(1) Total includes depreciation of corporate assets.

Depletion and depreciation expense of $131.2 million ($19.79/boe) for Q2/2017 increased by $9.2 million from $121.9 million ($19.13/boe). In Canada, depletion increased $5.2 million in Q2/2017 compared to Q2/2016 primarily due to higher production in

Q2/2017 as compared to Q2/2016. The U.S. depletion rate increased relative to Q2/2016 as a result of a weaker CAD/USD exchange which resulted in a higher depletion and depreciation expense reported in Canadian dollars.

The Company recorded depletion and depreciation expense of $253.5 million ($19.71/boe) for the six months ended June 30, 2017, down from $263.6 million ($19.87/boe) for the same period of 2016. In Canada, depletion for the six months ended was $101.9 million which was consistent with $101.6 million recorded for YTD 2016 with the depletion rate and production being similar in both periods. Depletion and depreciation expense recorded on U.S. oil and gas properties was lower as a result of lower production levels for the first six months of 2017 relative to the first six months of 2016.

General and Administrative Expense

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2017**	2016	Change	**2017**	2016	Change
General and administrative expense	**$ 14,015**	$ 12,233	$ 1,782	**$ 26,598**	$ 26,402	$ 196
General and administrative expense per boe	**$ 2.12**	$ 1.92	$ 0.20	**$ 2.07**	$ 1.99	$ 0.08

General and administrative ("G&A") expense was $14.0 million or $2.12/boe for Q2/2017 and $26.6 million or $2.07/boe for the six months ended June 30, 2017. Our ongoing cost saving efforts and reductions in discretionary spending were offset by non-recurring restructuring costs of $2.2 million, associated with a reduction in staffing levels, that were recorded in Q2/2017. Exclusive of the non-recurring charges incurred during Q2/2017, G&A expense decreased relative to the comparative periods of 2016. We expect annual costs to be closer to guidance of approximately $2.00/boe with lower G&A costs anticipated for the remainder of 2017.

Share-Based Compensation Expense

Share-based compensation ("SBC") 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. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $5.6 million for Q2/2017 and $10.1 million for the six months ended June 30, 2017, up from $3.9 million and $8.4 million recorded for the three and six month comparative periods in 2016, respectively. SBC expense is higher during 2017 as the fair value assigned to units granted in 2017 is higher than the previous period grants.

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 varies depending on debt levels outstanding during the period and the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and discount rates used to present value the obligations.

Financing and interest expense was $29.3 million for Q2/2017 compared to $27.9 million in Q2/2016. The increase from 2016 is mainly a result of the CAD/USD exchange rate which resulted in a higher Canadian dollar equivalent interest expense on our US dollar denominated debt during 2017. The CAD/USD exchange rate averaged 1.3447 CAD/USD for Q2/2017 compared to 1.2885 CAD/USD for Q2/2016.

Financing and interest expense was $57.8 million for YTD 2017 compared to $56.9 million for YTD 2016. The amounts are fairly consistent for 2017 and 2016 as the average exchange rates and debt balances were consistent over the comparative periods.

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.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for exchange rates)	**2017**	2016	Change	**2017**	2016	Change
Unrealized foreign exchange (gain) loss	**$ (32,045)**	$ 3,549	$ (35,594)	**$ (43,383)**	$ (83,252)	$ 39,869
Realized foreign exchange gain	**(907)**	(222)	(685)	**(157)**	(764)	607
Foreign exchange (gain) loss	**$ (32,952)**	$ 3,327	$ (36,279)	**$ (43,540)**	$ (84,016)	$ 40,476
CAD/USD exchange rates:						
At beginning of period	**1.3322**	1.2971		**1.3427**	1.3840	
At end of period	**1.2983**	1.3009		**1.2983**	1.3009	

We recorded an unrealized foreign exchange gain of $32.0 million for Q2/2017 and $43.4 million for the six months ended June 30, 2017 due to the strengthening Canadian dollar compared to the U.S. dollar with a CAD/USD exchange rate of 1.2983 as at June 30, 2017 compared to the exchange rate of 1.3322 at March 31, 2017 and 1.3427 as at December 31, 2016.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions on our Canadian operations. We recorded a realized foreign exchange gains of $0.9 million and $0.2 million for the three and six months ended June 30, 2017, respectively, compared to gains of $0.2 million and $0.8 million for the same periods of 2016.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2017**	2016	Change	**2017**	2016	Change
Current income tax recovery	**$ (705)**	$ (2,284)	$ 1,579	**$ (1,441)**	$ (3,726)	$ 2,285
Deferred income tax recovery	**(23,295)**	(46,783)	23,488	**(35,740)**	(94,905)	59,165
Total income tax recovery	**$ (24,000)**	$ (49,067)	$ 25,067	**$ (37,181)**	$ (98,631)	$ 61,450

Current income tax recovery was $0.7 million for Q2/2017 and $1.4 million for the six months ended June 30, 2017, as compared to $2.3 million and $3.7 million for the same periods of 2016, respectively. The current tax recoveries relate to current year losses that have been carried back to recover income tax expense paid in previous years.

The Q2/2017 deferred income tax recovery of $23.3 million decreased $23.5 million from a recovery of $46.8 million in Q2/2016. The decreased recovery is due to an increase in the value of our financial derivative contracts at Q2/2017 compared to Q2/2016.

The Company recorded a deferred income tax recovery of $35.7 million for the six months ended June 30, 2017, down from $94.9 million recorded for the first six months of 2016. The decreased recovery is due to an increase in the value of our financial derivative contracts combined with an increase in the amount of tax pool claims required to shelter the higher taxable income earned during the six months ended June 30, 2017 as compared to the six months ended June 30, 2016.

As previously disclosed in note 15 to the December 31, 2016 consolidated financial statements, we received several reassessments from the Canada Revenue Agency ("CRA") in June 2016. Those reassessments denied $591 million of non-capital loss deductions that we had previously claimed. In September 2016, we filed notices of objection with the CRA appealing each reassessment received and we are now waiting for an appeals officer to be assigned to our file. We remain confident that our original tax filings are correct and we intend to defend those tax filings through the appeals process available to us.

Net Income (Loss) and Funds from Operations

The components of FFO and net income (loss) for the three and six months ended June 30, 2017 and 2016 are set forth in the table below:

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2017**	2016	Change	**2017**	2016	Change
Petroleum and natural gas sales	**$ 274,369**	$ 195,733	$ 78,636	**$ 534,918**	$ 349,331	$ 185,587
Royalties	**(60,014)**	(42,386)	(17,628)	**(117,191)**	(76,968)	(40,223)
Revenue, net of royalties	**214,355**	153,347	61,008	**417,727**	272,363	145,364
Expenses						
Operating	**(70,925)**	(55,275)	(15,650)	**(135,055)**	(124,955)	(10,100)
Transportation	**(8,973)**	(5,146)	(3,827)	**(17,015)**	(11,921)	(5,094)
Blending	**(13,260)**	(1,207)	(12,053)	**(23,317)**	(3,566)	(19,751)
General and administrative	**(14,015)**	(12,233)	(1,782)	**(26,598)**	(26,402)	(196)
Financing and interest	**(25,915)**	(24,789)	(1,126)	**(51,107)**	(51,600)	493
Realized financial derivatives gain	**2,649**	23,816	(21,167)	**2,923**	68,442	(65,519)
Realized foreign exchange gain	**907**	222	685	**157**	764	(607)
Other income (loss)	**(493)**	242	(735)	**(906)**	55	(961)
Current income tax recovery	**705**	2,284	(1,579)	**1,441**	3,726	(2,285)
Payments on onerous contracts	**(1,899)**	—	(1,899)	**(3,745)**	—	(3,745)
Funds from operations	**$ 83,136**	$ 81,261	1,875	**$ 164,505**	$ 126,906	37,599
Exploration and evaluation	**(3,686)**	(1,896)	(1,790)	**(5,008)**	(3,359)	(1,649)
Depletion and depreciation	**(131,155)**	(121,940)	(9,215)	**(253,486)**	(263,611)	10,125
Share based compensation	**(5,593)**	(3,933)	(1,660)	**(10,142)**	(8,373)	(1,769)
Non-cash financing and interest	**(3,378)**	(3,099)	(279)	**(6,692)**	(5,341)	(1,351)
Unrealized financial derivatives gain (loss)	**13,229**	(80,564)	93,793	**48,843**	(110,687)	159,530
Unrealized foreign exchange gain (loss)	**32,045**	(3,549)	35,594	**43,383**	83,252	(39,869)
Loss on disposition of oil and gas properties	**(524)**	—	(524)	**(524)**	(22)	(502)
Deferred income tax recovery	**23,295**	46,783	(23,488)	**35,740**	94,905	(59,165)
Payments on onerous contracts	**1,899**	—	1,899	**3,745**	—	3,745
Net income (loss) for the period	**$ 9,268**	$ (86,937)	$ 96,205	**$ 20,364**	$ (86,330)	$ 106,694

We generated funds from operations of $83.1 million for Q2/2017, up 2% from $81.3 million for Q2/2016 driven by increases in our realized sales pricing and average daily production. Operating, transportation and blending expenses were higher in Q2/2017 relative to the same quarter of 2016 primarily due to the re-activation of higher operating cost properties which were shut-in for a portion of Q2/2016, combined with the acquisition of higher operating cost properties in Q1/2017. General and administrative expenses for Q2/2017 were also higher than Q2/2016 as savings from our ongoing cost savings initiatives were offset by $2.2 million of non-recurring charges associated with staffing reductions. We recorded net income of $9.3 million for the second quarter of 2017 relative to a loss of $86.9 million for Q2/2016. This $96.2 million difference was primarily a result of changes in the mark-to-market value of our derivative financial instruments which accounted for $93.8 million of the difference in Q2/2017 compared to the same period of 2016.

Funds from operations for the first half of 2017 was $164.5 million compared to $126.9 million for the same period of 2016. Higher realized pricing more than offset the impact of slightly lower average daily production. Total royalties increased relative to 2016, but remained consistent as a percentage of revenues. Increases in our operating, transportation and blending expenses for the first half of 2017 are attributable to re-activated production and the acquisition completed in Q1/2017 which have higher operating costs than our other properties. Fluctuations in commodity prices and the CAD/USD exchange rate resulted in changes in the carrying amount of our financial derivatives and our USD denominated debt. These factors combined to increase net income by $106.7 million to $20.4 million being reported for the first half of 2017 compared to a net loss of $86.3 million during the same period of 2016.

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 $80.3 million foreign currency translation loss recorded for the six months ended June 30, 2017 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 June 30, 2017 which was 1.2983 CAD/USD as compared to 1.3427 CAD/USD as at December 31, 2016.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2017 and 2016 are summarized as follows:

	Three Months Ended June 30					
	2017			2016		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 1,050**	**$ —**	**$ 1,050**	$ 1,374	$ 6,097	$ 7,471
Seismic	**145**	**—**	**145**	58	—	58
Drilling, completion and equipping	**12,834**	**54,701**	**67,535**	378	26,285	26,663
Facilities	**4,410**	**4,867**	**9,277**	937	361	1,298
Total exploration and development	**$ 18,439**	**$ 59,568**	**$ 78,007**	$ 2,747	$ 32,743	$ 35,490
Total acquisitions, net of proceeds from divestitures	**5,226**	**—**	**5,226**	(37)	—	(37)
Total oil and natural gas expenditures	**$ 23,665**	**$ 59,568**	**$ 83,233**	$ 2,710	$ 32,743	$ 35,453
Wells drilled (net)	**5.9**	**9.4**	**15.3**	—	11.3	11.3

	Six Months Ended June 30					
	2017			2016		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 2,327**	**$ —**	**$ 2,327**	$ 2,237	$ 6,097	$ 8,334
Seismic	**484**	**—**	**484**	113	—	113
Drilling, completion and equipping	**48,111**	**110,060**	**158,171**	3,810	95,966	99,776
Facilities	**5,999**	**7,585**	**13,584**	1,445	7,507	8,952
Total exploration and development	**$ 56,921**	**$ 117,645**	**$ 174,566**	$ 7,605	$ 109,570	$ 117,175
Total acquisitions, net of proceeds from divestitures	**71,230**	**—**	**71,230**	(46)	—	(46)
Total oil and natural gas expenditures	**$ 128,151**	**$ 117,645**	**$ 245,796**	$ 7,559	$ 109,570	$ 117,129
Wells drilled (net)	**33.0**	**17.8**	**50.8**	1.0	23.8	24.8

Our exploration and development activities before acquisitions and divestitures, were $78.0 million during Q2/2017, up from $35.5 million for the same quarter of 2016. Activity levels were lower in Q2/2016 as capital spending was reduced in response to the lower commodity price environment.

Exploration and development expenditures in Canada were $18.4 million for Q2/2017, an increase of $15.7 million from $2.7 million for Q2/2016. We continued to advance our operated drilling program after deferring all operated heavy oil drilling in 2016. For Q2/2017, we drilled 8.0 (5.9 net) wells and incurred drilling, completion and equipping costs of $12.8 million compared to nil (nil net) wells drilled in Q2/2016. In Peace River, our cost savings initiatives have resulted in drill, completion and equipping costs of $2.5 million for operated wells drilled during the first half of 2017. Applying multi-lateral drilling and production techniques to our operated wells in Lloydminster has resulted in average drill, completion and equipping costs of $0.8 million per well in 2017.

In the U.S., capital spending increased to $59.6 million in Q2/2017 from $32.7 million in Q2/2016. We drilled 9.4 net wells in the Eagle Ford in Q2/2017 compared to 11.3 net wells in Q2/2016. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$4.7 million to US$4.9 million per well, down from approximately US$5.4 million per well in 2016.

Total exploration and development expenditures were $174.6 million for the six months ended June 30, 2017, up from $117.2 million incurred for the same period of 2016. The increase in capital expenditures reflects higher activity levels compared to 2016 where capital activity in Canada was curtailed in response to low commodity prices. In Q1/2017, we initiated an active operated drilling program which continued through the end of the second quarter with 40.0 (33.0 net) wells drilled in the first half of 2017. Total oil and natural gas expenditures in the U.S. were $117.6 million for the six months ended June 30, 2017, up from $109.6 million for the first half of 2016 due to higher activity levels relative to the comparative period. We had 4-5 drilling rigs and 1-2 completion crew active on our lands through the first half of 2017, higher than the first half of 2016 where activity was lower in response to lower commodity prices.

Acquisitions net of divestitures totaled $71.2 million for the six months ended June 30, 2017 and include the Q1/2017 Peace River acquisition which closed on January 20, 2017 for consideration of $66.1 million. Other minor acquisition and disposition activity accounted for the remaining $5.1 million in 2017.

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 honour 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 FFO. As a result, we target annual exploration and development capital expenditures to approximate FFO in order to minimize additional bank borrowings. In 2016, we worked with our lending syndicate to secure our bank credit facilities and restructured the financial covenants applicable to such facilities, which reduced the cost of borrowings and increased our financial flexibility.

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

At June 30, 2017, net debt was $1.82 billion, as compared to $1.77 billion at December 31, 2016, representing an increase of $45.8 million. The increase largely reflects the timing of the Peace River acquisition for $66.1 million, which was prefunded by a $115.0 million equity issuance that closed in December 2016, along with exploration and development expenditures and abandonment and reclamation spending that exceeded FFO by $18.0 million for the six months ended June 30, 2017. This was offset by the strengthening Canadian dollar against the U.S. dollar at June 30, 2017 compared to December 31, 2016 which reduced the carrying value of our U.S. dollar denominated long-term notes and bank loans.

Bank Loan

Our 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 Q2/2017 was 4.0%, as compared to 3.5% for Q2/2016.

The following table summarizes the financial covenants contained in our Revolving Facilities and our compliance therewith as at June 30, 2017.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at June 30, 2017**	**June 30, 2017 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)	**0.7:1.00**	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage [(3)] (Minimum Ratio)	**4.0:1.00**	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at June 30, 2017, our Senior Secured Debt totaled $278 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 June 30, 2017 was $416 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended June 30, 2017 were $103 million.

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

Long-Term Notes

We have five series of long-term notes outstanding that total $1.54 billion as at June 30, 2017. 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 June 30, 2017, the fixed charge coverage ratio was 4.0:1.00.

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. As of July 19, 2017, these notes are redeemable at our option, in whole or in part, 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. 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.

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. During the six months ended June 30, 2017, we issued 755,100 common shares pursuant to our share-based compensation program. As at July 31, 2017, we had 235,450,452 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 June 30, 2017 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	**$ 128,427**	$ 128,427	$ —	$ —	$ —
Bank loan[1] [2]	**264,032**	—	264,032	—	—
Long-term notes[2]	**1,541,694**	—	8,309	714,065	819,320
Interest on long-term notes[3]	**456,589**	89,470	178,789	131,138	57,192
Operating leases	**34,751**	8,063	14,601	12,087	—
Processing agreements	**45,114**	9,703	9,592	9,032	16,787
Transportation agreements	**57,390**	12,039	24,376	19,576	1,399
Total	**$ 2,527,997**	$ 247,702	$ 499,699	$ 885,898	$ 894,698

(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.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2017, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the six months ended June 30, 2017. Further information on our critical accounting policies and estimates can be found in the notes to the annual consolidated financial statements and MD&A for the year ended December 31, 2016.

CHANGES IN ACCOUNTING STANDARDS

We did not adopt any new accounting standards for the six months ended June 30, 2017. A description of accounting standards that will be effective in the future is included in the notes to the audited consolidated financial statements and MD&A for the year ended December 31, 2016.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended June 30, 2017.

2017 GUIDANCE

The following table summarizes our 2017 annual guidance and compares it to our YTD 2017 actual results.

	2017 Guidance			
	Original	Revised	YTD 2017	Variance
Exploration and development capital ($ millions)	300 - 350	310 - 330	174.6	N/A
Production (boe/d)	66,000 - 70,000	69,000 - 70,000	71,065	2 %
Expenses:				
Royalty rate (%)	~23.0	~23.0	22.8	(1)%
Operating ($/boe)	11.00 - 12.00	10.75 - 11.25	10.50	(2)%
Transportation ($/boe)	1.10 - 1.30	1.10 - 1.30	1.32	2 %
General and administrative ($/boe)	~2.00	~2.00	2.07	4 %
Interest ($/boe)	~4.00	~4.00	3.97	(1)%

QUARTERLY FINANCIAL INFORMATION

	2017		2016				2015	
($ thousands, except per common share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**274,369**	260,549	233,116	197,648	195,733	153,598	229,361	265,876
Net income (loss)	**9,268**	11,096	(359,424)	(39,430)	(86,937)	607	(419,175)	(519,247)
Per common share - basic	**0.04**	0.05	(1.66)	(0.19)	(0.41)	—	(1.99)	(2.50)
Per common share - diluted	**0.04**	0.05	(1.66)	(0.19)	(0.41)	—	(1.99)	(2.50)
Funds from operations	**83,136**	81,369	77,239	72,106	81,261	45,645	93,095	105,052
Per common share - basic	**0.35**	0.35	0.36	0.34	0.39	0.22	0.44	0.51
Per common share - diluted	**0.35**	0.34	0.36	0.34	0.39	0.22	0.44	0.51
Exploration and development	**78,007**	96,559	68,029	39,579	35,490	81,685	140,796	126,804
Canada	**18,439**	38,484	12,151	6,120	2,747	4,855	8,804	33,484
U.S.	**59,568**	58,075	55,878	33,459	32,743	76,830	131,992	93,320
Acquisitions, net of divestitures	**5,226**	66,004	(322)	(62,752)	(37)	(9)	(574)	(498)
Net debt	**1,819,387**	1,850,909	1,773,541	1,864,022	1,942,538	1,981,343	2,049,905	1,949,736
Total assets	**4,582,049**	4,702,423	4,594,085	4,995,876	5,089,280	5,197,913	5,488,498	5,893,759
Common shares outstanding	**234,204**	234,203	233,449	211,542	210,715	210,689	210,583	210,225
Daily production								
Total production (boe/d)	**72,812**	69,298	65,136	67,167	70,031	75,776	81,110	82,170
Canada (boe/d)	**34,284**	33,217	31,704	33,615	31,722	34,709	40,826	43,229
U.S. (boe/d)	**38,528**	36,081	33,432	33,552	38,309	41,067	40,284	38,941
Benchmark prices								
WTI oil (US$/bbl)	**48.28**	51.91	49.29	44.94	45.60	33.45	42.18	46.43
WCS heavy (US$/bbl)	**37.16**	37.34	34.97	31.44	32.29	19.22	27.69	33.13
CAD/USD avg exchange rate	**1.3447**	1.3229	1.3339	1.3051	1.2885	1.3748	1.3353	1.3094
AECO gas ($/mcf)	**2.77**	2.94	2.81	2.20	1.25	2.11	2.65	2.70
NYMEX gas (US$/mmbtu)	**3.18**	3.32	2.98	2.81	1.95	2.09	2.27	2.77
Sales price ($/boe)	**39.41**	40.16	38.16	31.73	30.52	21.93	30.03	34.59
Royalties ($/boe)	**9.06**	9.17	9.28	7.37	6.65	5.02	6.61	7.61
Operating expense ($/boe)	**10.70**	10.28	9.96	9.07	8.67	10.11	9.76	10.25
Transportation expense ($/boe)	**1.35**	1.29	1.30	1.38	0.81	0.98	1.45	1.52
Operating netback ($/boe)	**18.30**	19.42	17.62	13.91	14.39	5.82	12.21	15.21
Financial derivatives gain ($/boe)	**0.40**	0.04	1.62	3.04	3.74	6.47	4.09	3.33
Operating netback after financial derivatives gain ($/boe)	**18.70**	19.46	19.24	16.95	18.13	12.29	16.30	18.54

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; our target of funding our exploration and development capital expenditures with funds from operations to minimize additional bank borrowings; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices;

our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; our expectation for general and administrative expense to be lower in H2/2017 than H1/2017; the cost to drill, complete and equip a well in the Eagle Ford, at Peace River and at Lloydminster; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honour outstanding obligations to us in the normal course of business; the existence, operation and strategy of our risk management program; our 2017 production and capital expenditure guidance; and our expected royalty rate and per boe operating, transportation, general and administrative, and interest costs for 2017. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands of Canadian dollars) (unaudited)

As at		June 30, 2017		December 31, 2016
ASSETS				
Current assets				
Cash	$	2,369	$	2,705
Trade and other receivables		112,397		112,171
Financial derivatives (note 17)		21,249		2,219
		136,015		117,095
Non-current assets				
Financial derivatives (note 17)		4,456		—
Exploration and evaluation assets (note 6)		300,721		308,462
Oil and gas properties (note 7)		4,125,565		4,152,169
Other plant and equipment		15,292		16,359
	$	4,582,049	$	4,594,085
LIABILITIES				
Current liabilities				
Trade and other payables	$	128,427	$	112,973
Financial derivatives (note 17)		4,985		28,532
Onerous contracts		5,644		9,504
		139,056		151,009
Non-current liabilities				
Bank loan (note 8)		261,754		187,954
Long-term notes (note 9)		1,525,344		1,566,116
Asset retirement obligations (note 10)		394,270		331,517
Deferred income tax liability		331,461		375,695
Financial derivatives (note 17)		1,023		2,833
		2,652,908		2,615,124
SHAREHOLDERS' EQUITY				
Shareholders' capital (note 11)		4,432,130		4,422,661
Contributed surplus		22,078		21,405
Accumulated other comprehensive income		549,537		629,863
Deficit		(3,074,604)		(3,094,968)
		1,929,141		1,978,961
	$	4,582,049	$	4,594,085

Subsequent events (note 17)
See accompanying notes to the condensed interim consolidated financial statements.

Baytex Energy Corp.

Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

(thousands of Canadian dollars, except per common share amounts) (unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	**2017**	2016
Revenue, net of royalties				
Petroleum and natural gas sales	**$ 274,369**	$ 195,733	**$ 534,918**	$ 349,331
Royalties	**(60,014)**	(42,386)	**(117,191)**	(76,968)
	214,355	153,347	**417,727**	272,363
Expenses				
Operating	**70,925**	55,275	**135,055**	124,955
Transportation	**8,973**	5,146	**17,015**	11,921
Blending	**13,260**	1,207	**23,317**	3,566
General and administrative	**14,015**	12,233	**26,598**	26,402
Exploration and evaluation (note 6)	**3,686**	1,896	**5,008**	3,359
Depletion and depreciation	**131,155**	121,940	**253,486**	263,611
Share-based compensation (note 12)	**5,593**	3,933	**10,142**	8,373
Financing and interest (note 15)	**29,293**	27,888	**57,799**	56,941
Financial derivatives (gain) loss (note 17)	**(15,878)**	56,748	**(51,766)**	42,245
Foreign exchange (gain) loss (note 16)	**(32,952)**	3,327	**(43,540)**	(84,016)
Loss on disposition of oil and gas properties	**524**	—	**524**	22
Other expense (income)	**493**	(242)	**906**	(55)
	229,087	289,351	**434,544**	457,324
Net loss before income taxes	**(14,732)**	(136,004)	**(16,817)**	(184,961)
Income tax recovery (note 14)				
Current income tax recovery	**(705)**	(2,284)	**(1,441)**	(3,726)
Deferred income tax recovery	**(23,295)**	(46,783)	**(35,740)**	(94,905)
	(24,000)	(49,067)	**(37,181)**	(98,631)
Net income (loss) attributable to shareholders	**$ 9,268**	$ (86,937)	**$ 20,364**	$ (86,330)
Other comprehensive income (loss)				
Foreign currency translation adjustment	**(62,163)**	6,062	**(80,326)**	(152,647)
Comprehensive loss	**$ (52,895)**	$ (80,875)	**$ (59,962)**	$ (238,977)
Net income (loss) per common share (note 13)				
Basic	**$ 0.04**	$ (0.41)	**$ 0.09**	$ (0.41)
Diluted	**$ 0.04**	$ (0.41)	**$ 0.09**	$ (0.41)
Weighted average common shares (note 13)				
Basic	**234,204**	210,749	**234,112**	210,687
Diluted	**236,615**	210,749	**236,715**	210,687

See accompanying notes to the condensed interim consolidated financial statements.

Baytex Energy Corp.

Condensed Consolidated Statements of Changes in Equity

(thousands of Canadian dollars) (unaudited)

	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	**Total equity**
Balance at December 31, 2015	$ 4,296,831	$ 22,045	$ 705,382	$ (2,609,784)	**$ 2,414,474**
Vesting of share awards	3,138	(3,138)	—	—	**—**
Share-based compensation	—	8,373	—	—	**8,373**
Comprehensive loss for the period	—	—	(152,647)	(86,330)	**(238,977)**
Balance at June 30, 2016	$ 4,299,969	$ 27,280	$ 552,735	$ (2,696,114)	**$ 2,183,870**
Balance at December 31, 2016	$ 4,422,661	$ 21,405	$ 629,863	$ (3,094,968)	**$ 1,978,961**
Vesting of share awards	9,469	(9,469)	—	—	**—**
Share-based compensation	—	10,142	—	—	**10,142**
Comprehensive loss for the period	—	—	(80,326)	20,364	**(59,962)**
Balance at June 30, 2017	$ 4,432,130	$ 22,078	$ 549,537	$ (3,074,604)	**$ 1,929,141**

See accompanying notes to the condensed interim consolidated financial statements.

Baytex Energy Corp.
Condensed Consolidated Statements of Cash Flows
(thousands of Canadian dollars) (unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	**2017**	2016
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	**$ 9,268**	$ (86,937)	**$ 20,364**	$ (86,330)
Adjustments for:				
Share-based compensation (note 12)	**5,593**	3,933	**10,142**	8,373
Unrealized foreign exchange (gain) loss (note 16)	**(32,045)**	3,549	**(43,383)**	(83,252)
Exploration and evaluation (note 6)	**3,686**	1,896	**5,008**	3,359
Depletion and depreciation	**131,155**	121,940	**253,486**	263,611
Non-cash financing and accretion (note 15)	**3,378**	3,099	**6,692**	5,341
Unrealized financial derivatives (gain) loss (note 17)	**(13,229)**	80,564	**(48,843)**	110,687
Loss on disposition of oil and gas properties	**524**	—	**524**	22
Deferred income tax recovery	**(23,295)**	(46,783)	**(35,740)**	(94,905)
Payments on onerous contracts	**(1,899)**	—	**(3,745)**	—
Change in non-cash working capital	**(10,427)**	(25,592)	**(5,637)**	(5,183)
Asset retirement obligations settled (note 10)	**(2,468)**	(708)	**(7,895)**	(2,409)
	70,241	54,961	**150,973**	119,314
Financing activities				
Increase in bank loan	**8,615**	53,864	**80,550**	104,607
	8,615	53,864	**80,550**	104,607
Investing activities				
Additions to exploration and evaluation assets (note 6)	**(1,052)**	(1,508)	**(4,837)**	(2,573)
Additions to oil and gas properties (note 7)	**(76,955)**	(33,982)	**(169,729)**	(114,602)
Divestitures	**300**	37	**380**	46
Property acquisitions (note 4)	**(5,526)**	—	**(71,610)**	—
Dispositions to other plant and equipment, net of additions	**(514)**	(52)	**(618)**	(374)
Change in non-cash working capital	**6,085**	(73,083)	**15,624**	(104,318)
	(77,662)	(108,588)	**(230,790)**	(221,821)
Impact of foreign currency translation on cash balances	**(1,876)**	(270)	**(1,069)**	(1,928)
Change in cash	**(682)**	(33)	**(336)**	172
Cash, beginning of period	**3,051**	452	**2,705**	247
Cash, end of period	**$ 2,369**	$ 419	**$ 2,369**	$ 419
Supplementary information				
Interest paid	**$ 30,775**	$ 30,222	**$ 50,194**	$ 51,876
Income taxes paid	**$ 386**	$ —	**$ 872**	$ 5,138

See accompanying notes to the condensed interim consolidated financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.
The audited consolidated financial statements of the Company as at and for the year ended December 31, 2016 are available through our filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

2. BASIS OF PRESENTATION

These condensed consolidated interim unaudited financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (the "IASB"), and do not include all of the necessary annual disclosures as prescribed by IFRS. Accordingly, these condensed consolidated interim unaudited financial statements should be read in conjunction with the annual audited consolidated financial statements as at and for the year ended December 31, 2016 (the "2016 annual financial statements").

These consolidated financial statements were approved by the Board of Directors of Baytex on July 31, 2017.

The consolidated financial statements have been prepared on a historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2016 annual financial statements have been applied in the preparation of these condensed consolidated interim unaudited financial statements.

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 identifying and reviewing its various revenue streams and underlying contracts and evaluating the impact on the consolidated financial statements as well as determining the extent of new additional disclosures.

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 in the process of identifying and reviewing its various lease contracts and arrangements in order to evaluate the impact on the consolidated financial statements.

4. PROPERTY ACQUISITION

On January 20, 2017, Baytex acquired heavy oil properties in the Peace River area of Alberta for total consideration of $66.1 million, including closing adjustments. The purchase price was adjusted for the results of operations between the effective date of December 1, 2016 and closing of the acquisition. The acquired properties provide additional development opportunities located immediately adjacent to Baytex's existing Peace River lands.

The acquisition was accounted for as a business combination whereby the net assets acquired and the liabilities assumed were recorded at fair value at the acquisition date. The estimated fair value of the oil and gas properties acquired was determined using internal estimates of proved plus probable reserves. The asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment, restoration and reclamation of the wells and facilities acquired using a market discount rate of 12%.

Preliminary estimates of fair value assigned to the assets acquired and liabilities assumed at the date of acquisition are set forth below:

Consideration for the acquisition:		
Cash paid	$	66,084
Total consideration	**$**	**66,084**
Allocation of purchase price:		
Oil and gas properties	$	89,526
Crude oil inventory[1]		988
Trade and other payables		(5,400)
Asset retirement obligations		(19,030)
Total net assets acquired	**$**	**66,084**

(1) Crude oil inventory is included as part of trade and other receivables.

For the period from January 20, 2017 to June 30, 2017, the acquired properties contributed revenues, net of royalties, of $18.4 million and operating income (revenues, net of royalties, less operating, transportation and blending expenses) of $4.8 million.

The fair value of identifiable assets acquired and liabilities assumed are preliminary, pending finalization of the annual reserves evaluation.

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	
Three Months Ended June 30	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 118,896**	$ 75,696	**$ 155,473**	$ 120,037	**$ —**	$ —	**$ 274,369**	$ 195,733
Royalties	**(14,119)**	(7,920)	**(45,895)**	(34,466)	**—**	—	**(60,014)**	(42,386)
	104,777	67,776	**109,578**	85,571	**—**	—	**214,355**	153,347
Expenses								
Operating	**45,981**	31,280	**24,944**	23,995	**—**	—	**70,925**	55,275
Transportation	**8,973**	5,146	**—**	—	**—**	—	**8,973**	5,146
Blending	**13,260**	1,207	**—**	—	**—**	—	**13,260**	1,207
General and administrative	**—**	—	**—**	—	**14,015**	12,233	**14,015**	12,233
Exploration and evaluation	**3,686**	1,896	**—**	—	**—**	—	**3,686**	1,896
Depletion and depreciation	**52,034**	46,843	**78,617**	74,470	**504**	627	**131,155**	121,940
Share-based compensation	**—**	—	**—**	—	**5,593**	3,933	**5,593**	3,933
Financing and interest	**—**	—	**—**	—	**29,293**	27,888	**29,293**	27,888
Financial derivatives (gain) loss	**—**	—	**—**	—	**(15,878)**	56,748	**(15,878)**	56,748
Foreign exchange (gain) loss	**—**	—	**—**	—	**(32,952)**	3,327	**(32,952)**	3,327
Loss on disposition of oil and gas properties	**524**	—	**—**	—	**—**	—	**524**	—
Other expense (income)	**—**	—	**—**	—	**493**	(242)	**493**	(242)
	124,458	86,372	**103,561**	98,465	**1,068**	104,514	**229,087**	289,351
Net income (loss) before income taxes	**(19,681)**	(18,596)	**6,017**	(12,894)	**(1,068)**	(104,514)	**(14,732)**	(136,004)
Income tax recovery								
Current income tax recovery	**—**	(1,958)	**(705)**	—	**—**	(326)	**(705)**	(2,284)
Deferred income tax recovery	**(6,146)**	(3,814)	**(11,042)**	(16,928)	**(6,107)**	(26,041)	**(23,295)**	(46,783)
	(6,146)	(5,772)	**(11,747)**	(16,928)	**(6,107)**	(26,367)	**(24,000)**	(49,067)
Net income (loss)	**$ (13,535)**	$ (12,824)	**$ 17,764**	$ 4,034	**$ 5,039**	$ (78,147)	**$ 9,268**	$ (86,937)
Total oil and natural gas capital expenditures (1)	**23,665**	2,710	**59,568**	32,743	**—**	—	**83,233**	35,453

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

Six Months Ended June 30	Canada 2017	Canada 2016	U.S. 2017	U.S. 2016	Corporate 2017	Corporate 2016	Consolidated 2017	Consolidated 2016
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 227,047**	$ 120,844	**$ 307,871**	$ 228,487	**$ —**	$ —	**$ 534,918**	$ 349,331
Royalties	**(26,752)**	(11,755)	**(90,439)**	(65,213)	**—**	—	**(117,191)**	(76,968)
	200,295	109,089	**217,432**	163,274	**—**	—	**417,727**	272,363
Expenses								
Operating	**89,384**	65,925	**45,671**	59,030	**—**	—	**135,055**	124,955
Transportation	**17,015**	11,921	**—**	—	**—**	—	**17,015**	11,921
Blending	**23,317**	3,566	**—**	—	**—**	—	**23,317**	3,566
General and administrative	**—**	—	**—**	—	**26,598**	26,402	**26,598**	26,402
Exploration and evaluation	**5,008**	3,359	**—**	—	**—**	—	**5,008**	3,359
Depletion and depreciation	**101,865**	101,628	**149,970**	160,609	**1,651**	1,374	**253,486**	263,611
Share-based compensation	**—**	—	**—**	—	**10,142**	8,373	**10,142**	8,373
Financing and interest	**—**	—	**—**	—	**57,799**	56,941	**57,799**	56,941
Financial derivatives (gain) loss	**—**	—	**—**	—	**(51,766)**	42,245	**(51,766)**	42,245
Foreign exchange (gain) loss	**—**	—	**—**	—	**(43,540)**	(84,016)	**(43,540)**	(84,016)
Loss on disposition of oil and gas properties	**524**	—	**—**	—	**—**	22	**524**	22
Other expense (income)	**—**	—	**—**	—	**906**	(55)	**906**	(55)
	237,113	186,399	**195,641**	219,639	**1,790**	51,286	**434,544**	457,324
Net income (loss) before income taxes	**(36,818)**	(77,310)	**21,791**	(56,365)	**(1,790)**	(51,286)	**(16,817)**	(184,961)
Income tax recovery								
Current income tax recovery	**—**	(3,400)	**(1,441)**	—	**—**	(326)	**(1,441)**	(3,726)
Deferred income tax recovery	**(10,774)**	(18,548)	**(18,562)**	(45,328)	**(6,404)**	(31,029)	**(35,740)**	(94,905)
	(10,774)	(21,948)	**(20,003)**	(45,328)	**(6,404)**	(31,355)	**(37,181)**	(98,631)
Net income (loss)	**$ (26,044)**	$ (55,362)	**$ 41,794**	$ (11,037)	**$ 4,614**	$ (19,931)	**$ 20,364**	$ (86,330)
Total oil and natural gas capital expenditures [1]	**128,151**	7,559	**117,645**	109,570	**—**	—	**245,796**	117,129

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

As at	June 30, 2017	December 31, 2016
Canadian assets	**$ 1,726,346**	$ 1,625,546
U.S. assets	**2,820,463**	2,955,965
Corporate assets	**35,240**	12,574
Total consolidated assets	**$ 4,582,049**	$ 4,594,085

6. EXPLORATION AND EVALUATION ASSETS

		June 30, 2017		December 31, 2016
Balance, beginning of period	$	**308,462**	$	578,969
Capital expenditures		**4,837**		4,716
Property acquisitions		**—**		102
Impairment		**—**		(166,617)
Exploration and evaluation expense		**(5,008)**		(5,976)
Transfer to oil and gas properties		**(1,280)**		(85,069)
Divestitures		**—**		(2,455)
Foreign currency translation		**(6,290)**		(15,208)
Balance, end of period	$	**300,721**	$	308,462

7. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
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**
Capital expenditures		169,729		—		169,729
Property acquisitions (note 4) [1]		96,030		—		96,030
Transferred from exploration and evaluation assets		1,280		—		1,280
Change in asset retirement obligations (note 10)		48,993		—		48,993
Divestitures		(2,951)		572		(2,379)
Foreign currency translation		(122,329)		33,906		(88,423)
Depletion		—		(251,834)		(251,834)
Balance, June 30, 2017	$	**7,954,789**	$	**(3,829,224)**	$	**4,125,565**

(1) Includes $6.5 million related to the acquisition of heavy oil producing properties during Q2/2017.

8. BANK LOAN

		June 30, 2017		December 31, 2016
Bank loan - U.S. dollar denominated[1]	$	**156,445**	$	191,286
Bank loan - Canadian dollar denominated		**107,587**		—
Bank loan - principal		**264,032**		191,286
Unamortized debt issuance costs		**(2,278)**		(3,332)
Bank loan	$	**261,754**	$	187,954

(1) U.S. dollar denominated bank loan balance as at June 30, 2017 was US$120.5 million (US$142.5 million as at December 31, 2016).

The 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 breaches 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 June 30, 2017, Baytex had $13.6 million of outstanding letters of credit (December 31, 2016 - $12.6 million) under the Revolving Facilities and 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 June 30, 2017.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at June 30, 2017**	**June 30, 2017 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)	0.7:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage (3) (Minimum Ratio)	4.0:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at June 30, 2017, the Company's Senior Secured Debt totaled $278 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 June 30, 2017 was $416 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses (excluding non-cash interest and accretion on asset retirement obligations) and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended June 30, 2017 were $103 million.

9. LONG-TERM NOTES

	June 30, 2017	December 31, 2016
7.5% notes (US$6,400 – principal) due April 1, 2020	**$ 8,309**	$ 8,593
6.75% notes (US$150,000 – principal) due February 17, 2021	**194,745**	201,405
5.125% notes (US$400,000 – principal) due June 1, 2021	**519,320**	537,080
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**519,320**	537,080
Total long-term notes - principal	**1,541,694**	1,584,158
Unamortized debt issuance costs	**(16,350)**	(18,042)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,525,344**	$ 1,566,116

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 8) to financing and interest expenses on a trailing twelve month basis) of 2.50:1. As at June 30, 2017, the fixed charge coverage ratio was 4.0:1.00.

10. ASSET RETIREMENT OBLIGATIONS

	June 30, 2017	December 31, 2016
Balance, beginning of period	**$ 331,517**	$ 296,002
Liabilities incurred	**3,114**	5,642
Liabilities settled	**(7,895)**	(5,616)
Liabilities divested	**(1,475)**	(10,590)
Property acquisitions (note 4) (1)	**20,007**	—
Accretion	**4,412**	6,174
Change in estimate(2)	**(17,200)**	20,402
Change in discount rate and inflation rate(3)(4)	**63,079**	20,260
Foreign currency translation	**(1,289)**	(757)
Balance, end of period	**$ 394,270**	$ 331,517

(1) Includes $1.0 million related to the acquisition of heavy oil producing properties during Q2/2017.

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

(3) The discount rate and inflation rate at June 30, 2017 are 2.00% and 1.50%, respectively, compared to 2.25% and 1.75% at December 31, 2016.

(4) The change in discount rate includes a $64 million adjustment related to the Peace River property acquisition in note 4. Obligations acquired are initially measured at fair value using a market rate of interest. The revaluation of obligations acquired using the risk-free discount rate results in an increase to the asset retirement obligation.

11. 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 June 30, 2017, 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, 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**
Transfer from contributed surplus on vesting and conversion of share awards	755	9,469
Balance, June 30, 2017	**234,204**	**$ 4,432,130**

12. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to outstanding share awards of $5.6 million for the three months ended June 30, 2017 and $10.1 million for the six months ended June 30, 2017. Compensation expense for the three and six months ended June 30, 2016 was $3.9 million and $8.4 million, respectively.

The weighted average fair value of share awards granted during the six months ended June 30, 2017 was $5.77 per restricted and performance award and $2.75 per restricted performance award for the six months ended June 30, 2016.

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, 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**
Granted	1,587	1,524	3,111
Vested and converted to common shares	(346)	(383)	(729)
Forfeited	(205)	(146)	(351)
Balance, June 30, 2017	**2,544**	**2,732**	**5,276**

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

13. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income (loss) per share based on the net income 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 applicable period.

	Three months ended June 30					
	2017			2016		
	Net income	**Common shares (000s)**	**Net income per share**	Net loss	Common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 9,268**	**234,204**	**$ 0.04**	$ (86,937)	210,749	$ (0.41)
Dilutive effect of share awards	**—**	**2,411**	**—**	—	—	—
Net income (loss) - diluted	**$ 9,268**	**236,615**	**$ 0.04**	$ (86,937)	210,749	$ (0.41)

	Six months ended June 30					
	2017			2016		
	Net income	**Common shares (000s)**	**Net income per share**	Net loss	Common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 20,364**	**234,112**	**$ 0.09**	$ (86,330)	210,687	$ (0.41)
Dilutive effect of share awards	**—**	**2,603**	**—**	—	—	—
Net income (loss) - diluted	**$ 20,364**	**236,715**	**$ 0.09**	$ (86,330)	210,687	$ (0.41)

The effect of 1.6 million share awards and 1.1 million share awards were excluded from the computation of diluted loss per share for the three months and six months ended June 30, 2017, as they were determined to be anti-dilutive. The effect of 3.8 million share awards was excluded from the computation of diluted loss per share for the three and six months ended June 30, 2016, as they were determined to be anti-dilutive.

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six months ended June 30	
	2017	2016
Net loss before income taxes	**$ (16,817)**	$ (184,961)
Expected income taxes at the statutory rate of 26.93% (2016 - 27.00%)(1)	**(4,529)**	(49,939)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	**2,732**	2,195
Non-taxable portion of foreign exchange gain	**(5,668)**	(10,655)
Effect of rate adjustments for foreign jurisdictions	**(23,301)**	(28,624)
Effect of change in deferred tax benefit not recognized	**(5,668)**	(10,655)
Other	**(747)**	(953)
Income tax recovery	**$ (37,181)**	$ (98,631)

(1) The statutory tax rate decreased due to a decrease in the corporate income tax rate in effect for Saskatchewan (from 12% to 11.75%)

As disclosed in the 2016 annual financial statements, Baytex received several reassessments from the Canada Revenue Agency ("CRA") in June 2016. Those reassessments denied $591 million of non-capital loss deductions that Baytex had previously claimed. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received and is now waiting for an appeals officer to be assigned to our file. Baytex remains confident that its original tax filings are correct and intend to defend those tax filings through the appeals process.

15. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	**2017**	2016
Interest on bank loan	**$ 3,035**	$ 2,690	**$ 5,588**	$ 6,301
Interest on long-term notes	**22,880**	22,099	**45,519**	45,299
Non-cash financing	**1,150**	1,531	**2,280**	2,111
Accretion on asset retirement obligations	**2,228**	1,568	**4,412**	3,230
Financing and interest	**$ 29,293**	$ 27,888	**$ 57,799**	$ 56,941

16. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	**2017**	2016
Unrealized foreign exchange (gain) loss	**$ (32,045)**	$ 3,549	**$ (43,383)**	$ (83,252)
Realized foreign exchange gain	**(907)**	(222)	**(157)**	(764)
Foreign exchange (gain) loss	**$ (32,952)**	$ 3,327	**$ (43,540)**	$ (84,016)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

	Assets		Liabilities	
	June 30, 2017	December 31, 2016	**June 30, 2017**	December 31, 2016
U.S. dollar denominated	**US$72,243**	US$66,950	**US$1,108,962**	US$1,197,732

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

	Remaining Term	Volume	Price/Unit (1)	Index	Fair Value as at June 30, 2017 *($millions)*
Oil					
Basis swap	Jul 2017 to Sep 2017	6,000 bbl/d	WTI less US$13.53/bbl	WCS $	(1.7)
Basis swap	Jul 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42/bbl	WCS $	(0.8)
Basis swap	Oct 2017 to Dec 2017	3,000 bbl/d	WTI less US$13.42/bbl	WCS $	(0.3)
Basis swap (3)	Oct 2017 to Dec 2017	1,000 bbl/d	WTI less US$12.00/bbl	WCS	N/A
Basis swap (3)	Jan 2018 to Jun 2018	2,000 bbl/d	WTI less US$14.23/bbl	WCS	N/A
Basis swap (3)	Jan 2018 to Dec 2018	3,000 bbl/d	WTI less US$14.48/bbl	WCS	N/A
Fixed - sell	Jul 2017 to Dec 2017	3,500 bbl/d	US$54.46/bbl	WTI $	6.4
3-way option (2)	Jul 2017 to Dec 2017	14,500 bbl/d	US$58.61/US$47.17/US$37.24	WTI $	8.0
3-way option (2)	Jan 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI $	5.0
Swaption (4)	Jan 2018 to Dec 2018	1,000 bbl/d	US$54.00/bbl	WTI $	2.0
Swaption (4)	Jan 2018 to Dec 2018	1,000 bbl/d	US$50.00/bbl	WTI $	(0.6)
Swaption (3)(4)	Jan 2018 to Dec 2018	1,500 bbl/d	US$51.00/bbl	WTI	N/A
Swaption (3)(4)	Jan 2018 to Dec 2018	1,000 bbl/d	US$50.10/bbl	WTI	N/A
Swaption (3)(4)	Jan 2018 to Dec 2018	500 bbl/d	US$50.90/bbl	WTI	N/A
Swaption (3)(4)	Jan 2018 to Dec 2018	500 bbl/d	US$52.00/bbl	WTI	N/A
Natural Gas					
Fixed - sell	Jul 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO $	1.9
Fixed - sell	Jul 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX $	(0.6)
Fixed - sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX $	—
Fixed - sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO $	0.4
Total				**$**	**19.7**
Current asset				$	21.2
Non-current asset				$	4.5
Current liability				$	(5.0)
Non-current liability				$	(1.0)

(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) Contract entered subsequent to June 30, 2017. For the purposes of the table, contracts entered subsequent to June 30, 2017 will have no fair value assigned.

(4) For these contracts, Baytex received a higher swap price in exchange for writing a call option whereby the holder has the right, if exercised on December 29, 2017, to enter an additional swap transaction for the same remaining term, notional volume and fixed price per unit.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2017	2016	**2017**	2016
Realized financial derivatives gain	**$ (2,649)**	$ (23,816)	**$ (2,923)**	$ (68,442)
Unrealized financial derivatives (gain) loss	**(13,229)**	80,564	**(48,843)**	110,687
Financial derivatives (gain) loss	**$ (15,878)**	$ 56,748	**$ (51,766)**	$ 42,245

Physical Delivery Contracts

As at June 30, 2017, Baytex had 2,000 bbl/d of WCS basis swap physical delivery contracts from October 2017 to December 2017 at a fixed price of WTI less US$13.85/bbl that 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.

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Baytex Energy Corp.

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Independent Businessman

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

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

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

Naveen Dargan(1)(2)
Independent Businessman

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

Edward D. LaFehr
President and Chief Executive Officer
Baytex Energy Corp.

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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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

OFFICERS

Edward D. LaFehr
President and Chief Executive Officer

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

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

AUDITORS

KPMG LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE