

BAYTEX

ENERGY CORP.

BUILDING OUR FUTURE

20 **17** / ANNUAL
REPORT



OUR OPERATING AREAS



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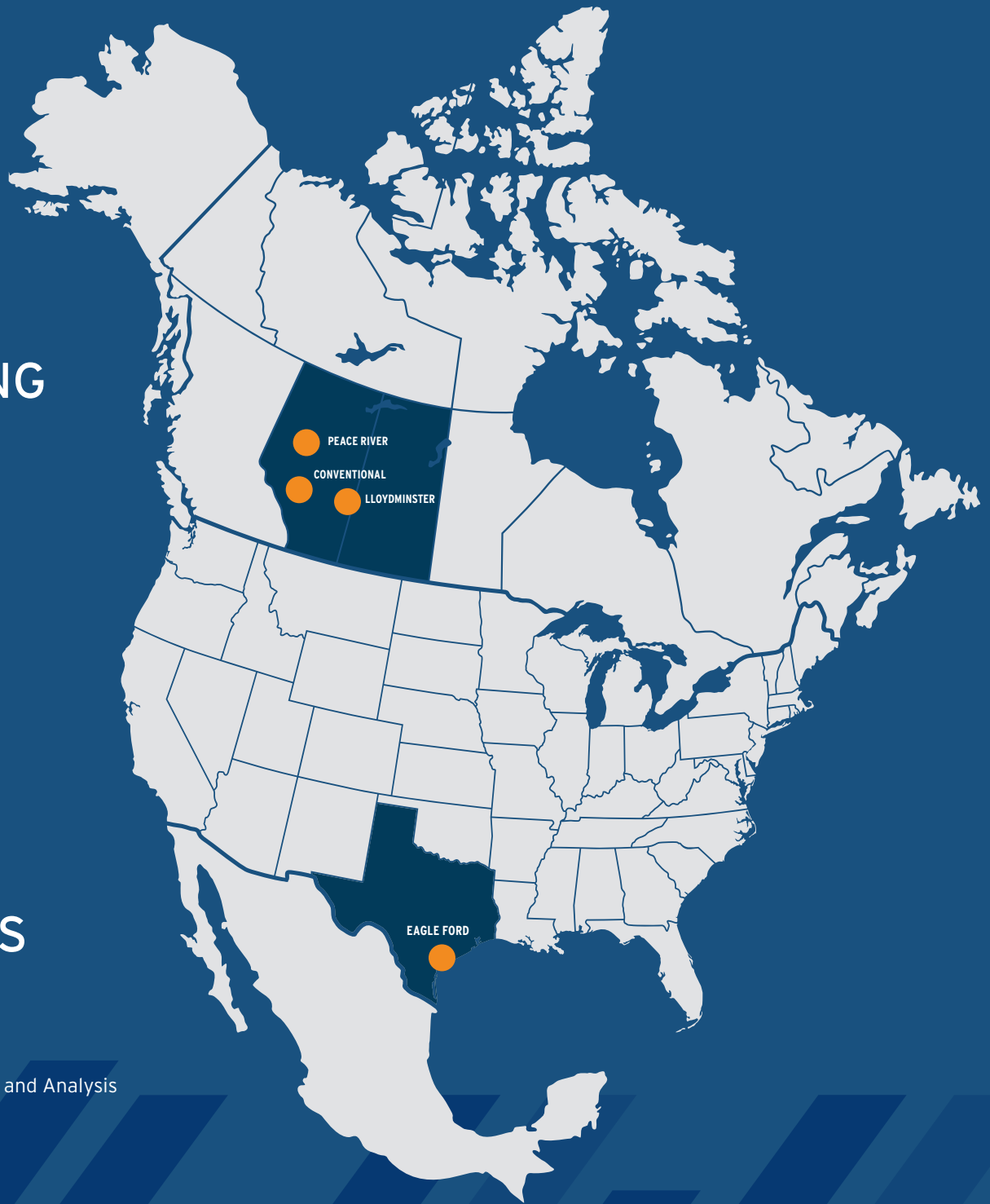
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SUMMARY

| | Years Ended | |
|--|----------------------|----------------------|
| | December 31, 2017 | December 31, 2016 |
| FINANCIAL <i>(thousands of Canadian dollars, except per common share amounts)</i> | | |
| Petroleum and natural gas sales | 1,091,534 | 780,095 |
| Adjusted funds flow⁽¹⁾ | 347,641 | 276,251 |
| Per share – basic | 1.48 | 1.30 |
| Per share – diluted | 1.47 | 1.30 |
| Net income (loss) | 87,174 | (485,184) |
| Per share – basic | 0.37 | (2.29) |
| Per share – diluted | 0.37 | (2.29) |
| Exploration and development | 326,266 | 224,783 |
| Acquisitions, net of divestitures | 59,857 | (63,120) |
| Total oil and natural gas capital expenditures | 386,123 | 161,663 |
| Bank loan⁽²⁾ | 213,376 | 191,286 |
| Long-term notes⁽²⁾ | 1,489,210 | 1,584,158 |
| Long-term debt | 1,702,586 | 1,775,444 |
| Working capital (surplus) deficiency | 31,698 | (1,903) |
| Net debt⁽³⁾ | 1,734,284 | 1,773,541 |
| OPERATING | | |
| Daily production | | |
| Heavy oil (bbl/d) | 25,326 | 23,586 |
| Light oil and condensate (bbl/d) | 21,314 | 21,377 |
| NGL (bbl/d) | 9,206 | 9,349 |
| Total oil and NGL (bbl/d) | 55,846 | 54,312 |
| Natural gas (mcf/d) | 86,375 | 91,182 |
| Oil equivalent (boe/d @ 6:1) ⁽⁴⁾ | 70,242 | 69,509 |
| Benchmark prices | | |
| WTI oil (US\$/bbl) | 50.95 | 43.33 |
| WCS heavy oil (US\$/bbl) | 38.97 | 29.49 |
| Edmonton par oil (\$/bbl) | 62.92 | 53.01 |
| LLS oil (US\$/bbl) | 53.26 | 43.82 |
| Baytex average prices (before hedging) | | |
| Heavy oil (\$/bbl) ⁽⁵⁾ | 38.46 | 26.46 |
| Light oil and condensate (\$/bbl) | 63.74 | 50.32 |
| NGL (\$/bbl) | 25.86 | 17.16 |
| Total oil and NGL (\$/bbl) | 46.03 | 34.25 |
| Natural gas (\$/mcf) | 3.24 | 2.69 |
| Oil equivalent (\$/boe) | 40.58 | 30.29 |
| CAD/USD noon rate at period end | 1.2518 | 1.3427 |
| CAD/USD average rate for period | 1.2979 | 1.3256 |

| | Years Ended | |
|--|----------------------|----------------------|
| | December 31, 2017 | December 31, 2016 |
| COMMON SHARE INFORMATION | | |
| TSX | | |
| Share price (Cdn\$) | | |
| High | 6.97 | 9.04 |
| Low | 2.76 | 1.57 |
| Close | 3.77 | 6.56 |
| Volume traded (thousands) | 823,591 | 1,677,986 |
| NYSE | | |
| Share price (US\$) | | |
| High | 5.20 | 7.14 |
| Low | 2.13 | 1.08 |
| Close | 2.76 | 4.48 |
| Volume traded (thousands) | 356,263 | 707,973 |
| Common shares outstanding (thousands) | 235,451 | 233,449 |

Notes:

- (1) *Adjusted funds flow 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 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 exclude condensate blending.*

Advisory Regarding Forward-Looking Statements and Initial Production Rates

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our strategy to target capital expenditures at a level that approximates our adjusted funds flow; our estimated net asset value; our Eagle Ford assets, including our assessment that it is a premier oil resource play, generates high cash netbacks and has a significant development inventory; that our Peace River assets can generate some of the strongest capital efficiencies in the oil and gas industry; that we expect to achieve further operating expense reductions on the assets acquired at Peace River in January 2017; our 2018 production and capital expenditure guidance; that we view the current price differential between West Texas Intermediate light oil and Canadian heavy oil as temporary; that we have operational flexibility to adjust our spending plans based on commodity prices; that we expect the Eagle Ford assets to generate significant free cash flow in 2018; and our ability to optimize our heavy oil netbacks through operational optimization, crude-by-rail and the use of financial and physical hedges. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that they can be profitably produced in the future. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking statements.

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

Non-GAAP Financial and Capital Management Measures

Adjusted funds flow is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017.

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 petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

2017 was a year about delivering on our commitments. Despite persistent low commodity prices, we delivered on our operational and financial targets, reduced our overall debt and acquired a strategic asset in Peace River. We continued to drive cost and capital efficiency in our business and increased our production, reserves and adjusted funds flow.

We achieved our best ever health, safety and environmental performance and strong regulatory compliance in all of our operating jurisdictions. We also published our third Corporate Responsibility Report, focusing on environmental, social and economic metrics. We believe that corporate responsibility is a key component to achieving enduring success in resource development.

We delivered annual production of 70,242 boe/d, above the high end of our guidance range while spending \$326 million in capital. When comparing actual results for the fourth quarter of 2017 to the fourth quarter of 2016, production increased 7%. We also delivered adjusted funds flow of \$348 million, an increase of 26% over 2016. Contributing to our adjusted funds flow was a reduction in cash costs (operating, transportation and general and administrative expenses) of 7.5% on a boe basis as compared to original guidance.

Net debt was reduced to \$1.73 billion, down from \$1.78 billion at year-end 2016, and we maintained strong financial liquidity with our US\$575 million revolving credit facilities 70% undrawn. During 2017, we targeted capital expenditures to approximate adjusted funds flow in order to minimize additional bank borrowings. We exceeded this goal with adjusted funds flow exceeding capital expenditures by \$21 million.

We grew our reserves with a capital investment portfolio that demonstrated continued success in the Eagle Ford along with the resumption of activity in Canada. We replaced 201% of production and increased proved plus probable reserves 6% to 432 mboe. Our finding and development costs, inclusive of changes in future development costs, were \$7.26/boe, generating a strong recycle ratio of 2.7x. Importantly, our net asset value increased 11% to \$10.08 per share (before tax and discounted at 10%).

Strong well performance in the Eagle Ford, driven by enhanced completions, led to 30-day initial gross production rates of approximately 1,450 boe/d. This represents a 12% improvement over 2016. In addition, the wells that commenced production during the fourth quarter represent some of the highest productivity wells drilled to-date on our lands. Two of these wells in our new northern Austin Chalk fracture trend demonstrated 30-day initial gross production rates of approximately 2,400 boe/d.

At Peace River, 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. Our 2017 drilling program in Peace River included 8 net multi-lateral horizontal wells.

We also successfully integrated our acquisition of additional heavy oil assets in the Peace River region that closed on January 20, 2017 and have made meaningful progress in reducing operating costs on the acquired assets. To-date, we have achieved a 35% reduction with further improvements anticipated in 2018 and beyond.

At Lloydminster, we adopted the multi-lateral well design and geosteering capability that we have successfully utilized at Peace River. Our 2017 drilling program in Lloydminster included 33 net wells, of which 45% were multi-lateral horizontal wells.

Looking Forward

We will continue to focus on our strategic priorities as we move forward with the intention to build on our health, safety, environmental and compliance culture while we drive cost and capital efficiency in our operations. We will strive to further grow production and reserves while looking for opportunities to balance our capital structure. We have budgeted exploration and development capital expenditures of \$325 to \$375 million for 2018 and expect to deliver average annual production of 68,000 to 72,000 boe/d.

At the time of writing, commodity prices remain volatile with the price for WTI currently above US\$60/bbl and Canadian heavy oil differentials averaging US\$24/bbl for Q1/2018 due to transportation challenges. We anticipate these wide differentials to be temporary as the industry works to alleviate the bottlenecks through crude by rail and existing pipeline optimization and reconfigurations. We remain supporters of Canadian pipeline expansion as the medium term solution to market access. As we navigate this volatility, we continue to have the operational flexibility to adjust our spending plans based on changes in the commodity price environment.


We are encouraged by our operating results in the Eagle Ford and the strong cash generating capability of this asset as the prices for Brent and LLS are above US\$63/bbl. During the fourth quarter, our netback in the Eagle Ford of \$30/boe was the highest we have realized since 2014. At current crude oil prices, we expect the Eagle Ford to generate significant free cash flow in 2018.

In Canada, we are executing our first quarter drilling and development program as planned with improved WTI pricing partially offsetting the widening of the Canadian heavy oil differential. We continue to manage our heavy oil sales portfolio through operational optimization, crude-by-rail and the use of financial and physical hedges to optimize our heavy oil netbacks.

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

We look forward to executing our plans in 2018 for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

A handwritten signature in black ink that reads "Edu D. LaFehr". The signature is written in a cursive, flowing style.

Edward D. LaFehr
President and Chief Executive Officer

March 6, 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2017 and 2016. This information is provided as of March 5, 2018. 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 months and year ended December 31, 2017 ("Q4/2017" and "2017") have been compared with the results for the three months and year ended December 31, 2016 ("Q4/2016" and "2016"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2017 and 2016, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2017. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

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

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain capital management measures (such as adjusted funds flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). While adjusted funds flow, 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 presented by other reporting issuers. We believe that inclusion of these non-GAAP financial measures provide useful information to investors and shareholders when evaluating the financial results of the Company.

Adjusted Funds Flow

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Adjusted funds flow 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 or loss.

The following table reconciles cash flow from operating activities to adjusted funds flow.

| (\$ thousands) | Years Ended December 31 | |
|--------------------------------------|-------------------------|------------|
| | 2017 | 2016 |
| Cash flow from operating activities | \$ 325,208 | \$ 247,365 |
| Change in non-cash working capital | 8,962 | 23,270 |
| Asset retirement obligations settled | 13,471 | 5,616 |
| Adjusted funds flow | \$ 347,641 | \$ 276,251 |

Net Debt

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

The following table summarizes our calculation of net debt.

| (\$ thousands) | December 31, 2017 | | December 31, 2016 | |
|---|-------------------|-----------|-------------------|-----------|
| Bank loan ⁽¹⁾ | \$ | 213,376 | \$ | 191,286 |
| Long-term notes ⁽¹⁾ | | 1,489,210 | | 1,584,158 |
| Working capital (surplus) deficiency ⁽²⁾ | | 31,698 | | (1,903) |
| Net debt | \$ | 1,734,284 | \$ | 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.

| (\$ thousands) | Years Ended December 31 | | | |
|---|-------------------------|-----------|------|---------|
| | 2017 | | 2016 | |
| Petroleum and natural gas sales | \$ | 1,091,534 | \$ | 780,095 |
| Blending expense | | (51,012) | | (9,622) |
| Total sales, net of blending expense | | 1,040,522 | | 770,473 |
| Royalties | | 241,892 | | 178,116 |
| Operating expense | | 269,283 | | 240,705 |
| Transportation expense | | 33,985 | | 28,257 |
| Operating netback | | 495,362 | | 323,395 |
| Realized financial derivative gain | | 7,616 | | 96,929 |
| Operating netback after realized financial derivatives gain | \$ | 502,978 | \$ | 420,324 |

Bank EBITDA

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

| (\$ thousands) | Years Ended December 31 | | | |
|---|-------------------------|-----------|------|-----------|
| | 2017 | | 2016 | |
| Net income (loss) | \$ | 87,174 | \$ | (485,184) |
| Plus: | | | | |
| Financing and interest | | 113,638 | | 114,199 |
| Unrealized foreign exchange gain | | (86,649) | | (41,436) |
| Unrealized financial derivatives loss | | 2,439 | | 140,136 |
| Current income tax recovery | | (1,085) | | (8,042) |
| Deferred income tax recovery | | (155,343) | | (264,561) |
| Depletion and depreciation | | 481,929 | | 508,309 |
| Impairment | | — | | 423,176 |
| Gain on disposition of oil and gas properties | | (12,081) | | (43,907) |
| Non-cash items ⁽¹⁾ | | 23,762 | | 29,974 |
| Bank EBITDA | \$ | 453,784 | \$ | 372,664 |

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

2017 ANNUAL HIGHLIGHTS

Baytex delivered solid operating and financial results for 2017. Strong well performance in the U.S. and Canada resulted in average production of 70,242 boe/d which exceeded the high end of our annual guidance range of 69,500 - 70,000 boe/d. The disciplined execution of our 2017 capital program resulted in exploration and development expenditures of \$326.3 million being fully funded by adjusted funds flow of \$347.6 million.

Total production of 70,242 boe/d for 2017 was 8% higher than Q4/2016 exit production of 65,136 boe/d. Strong well performance in the Eagle Ford and new well production from our Canadian capital program, combined with reactivations on the acquired Peace River properties, contributed to the increase in production for 2017 relative to Q4/2016.

In Canada, exploration and development expenditures of \$113.3 million were focused on our Peace River and Lloydminster properties. In total, we drilled 8.0 (8.0 net) wells at Peace River and 65.0 (32.7 net) wells at Lloydminster during 2017. Drilling results in both Peace River and Lloydminster have exceeded expectations after having limited activity on these lands in 2015 and 2016. Production for our Canadian operations averaged 33,564 boe/d for 2017, up from 32,936 boe/d reported for 2016. We closed the Peace River asset acquisition on January 20, 2017 and were able to reactivate certain wells which contributed to a 2% increase in production in Q4/2017 relative to Q4/2016.

In the U.S., exploration and development capital was \$213.0 million for 2017 and we drilled 140 (32.8 net) wells and commenced production from 115 (28.7 net) wells during the year. Drilling and completion activity increased in Q4/2016 and continued at a consistent pace throughout 2017 with approximately 4 drilling rigs and 2 completion crews on our lands. With this increased activity and strong well performance from enhanced completion techniques utilizing higher proppant loading and increased frac stages, production for Q4/2017 increased 12% to 37,362 boe/d from 33,432 boe/d in Q4/2016. Production for 2017 was 36,678 boe/d, relatively consistent with 36,573 boe/d in 2016.

During 2017, strengthening global oil demand combined with the ongoing efforts of the Organization of Petroleum Exporting Countries ("OPEC") to balance the oil market with production curtailments began to stabilize oil pricing at levels above the multi-year lows experienced during 2016. The West Texas Intermediate ("WTI") benchmark oil price averaged US\$50.95/bbl for 2017 which is an increase of 18% from US\$43.33/bbl for 2016. Despite a recent widening of the price differential for Canadian heavy oil in late Q4/2017, the differential narrowed from US\$13.84/bbl in 2016 to US\$11.98/bbl in 2017 due to increased downstream demand combined with higher pipeline capacity available as a result of downtime from other heavy oil producers in Western Canada. The improvement in commodity prices during 2017, combined with tighter heavy oil differentials in Canada and improved contract pricing in the U.S. increased our realized sales price to \$40.58/boe in 2017 from \$30.29/boe in 2016.

We generated adjusted funds flow of \$347.6 million for 2017, an increase of \$71.4 million from adjusted funds flow of \$276.3 million reported for 2016. The increase in adjusted funds flow in 2017 was primarily due to higher realized prices of \$40.58/boe, which increased \$10.29/boe as compared to \$30.29/boe reported for 2016. The increase in realized prices for 2017 was partially offset by higher royalties, operating and transportation expenses and resulted in a \$172.0 million or \$6.60/boe increase in operating netback from 2016. The increase in operating netback was offset by an \$89.3 million decrease in hedging gains as benchmark prices were higher relative to our contract prices in 2017 as compared to 2016.

At December 31, 2017, net debt was \$1,734.3 million, a decrease of \$39.2 million from \$1,773.5 million at December 31, 2016. Adjusted funds flow for 2017 exceeded exploration and development expenditures and settlement of asset retirement obligations by \$7.9 million which contributed to a reduction of net debt. The strengthening of the Canadian dollar reduced the reported amount of our U.S. dollar denominated debt at December 31, 2017 which more than offset the increase in net debt due to the Peace River acquisition that closed on January 20, 2017.

RESULTS OF OPERATIONS

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

Production

| | Years Ended December 31 | | | | | |
|-----------------------------|-------------------------|--------|--------|--------|--------|--------|
| | 2017 | | | 2016 | | |
| Daily Production | Canada | U.S. | Total | Canada | U.S. | Total |
| Liquids (bbl/d) | | | | | | |
| Heavy oil | 25,326 | — | 25,326 | 23,586 | — | 23,586 |
| Light oil and condensate | 1,163 | 20,151 | 21,314 | 1,407 | 19,970 | 21,377 |
| Natural Gas Liquids ("NGL") | 1,044 | 8,162 | 9,206 | 1,274 | 8,075 | 9,349 |
| Total liquids (bbl/d) | 27,533 | 28,313 | 55,846 | 26,267 | 28,045 | 54,312 |
| Natural gas (mcf/d) | 36,186 | 50,189 | 86,375 | 40,015 | 51,167 | 91,182 |
| Total production (boe/d) | 33,564 | 36,678 | 70,242 | 32,936 | 36,573 | 69,509 |
| Production Mix | | | | | | |
| Heavy oil | 76% | —% | 36% | 72% | —% | 34% |
| Light oil and condensate | 3% | 55% | 30% | 4% | 55% | 31% |
| NGL | 3% | 22% | 13% | 4% | 22% | 13% |
| Natural gas | 18% | 23% | 21% | 20% | 23% | 22% |

Our average production for 2017 was 70,242 boe/d which is consistent with 69,509 boe/d reported for 2016 and above the high end of our annual guidance range of 69,500 - 70,000 boe/d. Despite annual average production being consistent year over year, Q4/2017 production of 69,556 was up 7% from Q4/2016 due to strong well performance and higher activity levels in Canada and the U.S. relative to 2016 combined with the Peace River acquisition which closed on January 20, 2017.

In Canada, production of 33,564 boe/d for 2017 is consistent with average production of 32,936 boe/d reported for 2016. In Q4/2016, we increased the pace of development at Lloydminster and Peace River after having limited activity on these lands in 2015 and 2016. Positive results from our more active Canadian capital program combined with production from the Q1/2017 Peace River acquisition more than offset natural declines.

Production in the U.S. averaged 36,678 boe/d in 2017 which is consistent with 36,573 boe/d reported for 2016 despite the sale of approximately 1,000 boe/d of operated Eagle Ford production in Q3/2016. Strong performance from wells brought on production in late 2016 and throughout 2017 contributed to slightly higher average production relative to 2016. Enhanced completion techniques utilizing higher proppant loading and increased frac stages resulted in higher initial production rates from wells that commenced production in 2017 and resulted in Q4/2017 production of 37,362 boe/d as compared to 33,432 boe/d in Q4/2016.

Commodity Prices

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

Crude Oil

North American crude oil prices were higher in 2017 relative to the multi-year lows experienced during 2016. The WTI benchmark oil price is the representative index for inland North American light oil pricing at Cushing, Oklahoma. WTI pricing ranged between US \$45/bbl and US\$58/bbl during 2017 as strengthening global demand and geopolitical concerns over supply from the Middle East resulted in improved U.S. benchmark prices late in the year. The WTI light oil benchmark averaged US\$50.95/bbl for 2017, an increase of 18% from an average of US\$43.33/bbl during 2016.

Our U.S. crude oil production is primarily priced off 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. Increases in U.S. crude oil exports combined with an increase in global benchmark pricing has resulted in LLS trading at a premium to WTI for 2017. The LLS benchmark was US\$53.26/bbl or a US \$2.31/bbl premium to WTI for 2017 compared to US\$43.82/bbl or a US\$0.49/bbl premium to WTI in 2016.

The price received for our heavy oil sales in Canada is based on the Western Canadian Select ("WCS") benchmark price which trades at a discount to WTI due to the quality and lack of egress for Canadian grades of crude oil. The WCS heavy oil differential averaged US\$11.98/bbl in 2017, narrower than US\$13.84/bbl in 2016 as a result of an increase in demand and available pipeline capacity due to production downtime for other heavy oil producers. Pipeline outages in late 2017 have compounded existing transportation constraints and have resulted in increased crude inventories in Western Canada and a widening of the WCS heavy oil differential in Q4/2017.

Natural Gas

Natural gas prices were higher in 2017 relative to 2016 as increased exports to Mexico and increasing North American liquefied natural gas sales have resulted in lower storage levels. Canadian natural gas prices remain challenged as higher maintenance downtime on the Western Canadian pipeline system has created transportation bottlenecks and a lower AECO benchmark during the second half of 2017 as compared to 2016.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. During 2017, the NYMEX natural gas benchmark averaged US\$3.11/mmbtu, an increase of 26% from US\$2.46/mmbtu for 2016.

In Canada, we received natural gas pricing based on the AECO benchmark which averaged \$2.43/mcf during 2017. The AECO benchmark continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production.

The following tables compare selected benchmark prices and our average realized selling prices for the years ended December 31, 2017 and 2016.

| | Years Ended December 31 | | |
|---|-------------------------|--------|--------|
| | 2017 | 2016 | Change |
| Benchmark Averages | | | |
| WTI oil (US\$/bbl) ⁽¹⁾ | 50.95 | 43.33 | 18 % |
| WTI oil (CAD\$/bbl) | 66.13 | 57.44 | 15 % |
| WCS heavy oil (US\$/bbl) ⁽²⁾ | 38.97 | 29.49 | 32 % |
| WCS heavy oil (CAD\$/bbl) | 50.59 | 39.09 | 29 % |
| LLS oil (US\$/bbl) ⁽³⁾ | 53.26 | 43.82 | 22 % |
| LLS oil (CAD\$/bbl) | 69.12 | 58.08 | 19 % |
| CAD/USD average exchange rate | 1.2979 | 1.3256 | (2)% |
| Edmonton par oil (\$/bbl) | 62.92 | 53.01 | 19 % |
| AECO natural gas price (\$/mcf) ⁽⁴⁾ | 2.43 | 2.09 | 16 % |
| NYMEX natural gas price (US\$/mmbtu) ⁽⁵⁾ | 3.11 | 2.46 | 26 % |

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

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

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

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

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

Years Ended December 31

| | 2017 | | | 2016 | | |
|--|----------|----------|----------|----------|----------|----------|
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Average Realized Sales Prices⁽¹⁾ | | | | | | |
| Heavy oil (\$/bbl) ⁽²⁾ | \$ 38.46 | \$ — | \$ 38.46 | \$ 26.46 | \$ — | \$ 26.46 |
| Light oil and condensate (\$/bbl) | 56.24 | 64.17 | 63.74 | 46.21 | 50.60 | 50.32 |
| NGL (\$/bbl) | 27.98 | 25.59 | 25.86 | 17.77 | 17.06 | 17.16 |
| Natural gas (\$/mcf) | 2.21 | 3.99 | 3.24 | 2.01 | 3.21 | 2.69 |
| Weighted average (\$/boe) ⁽²⁾ | \$ 34.22 | \$ 46.41 | \$ 40.58 | \$ 24.06 | \$ 35.89 | \$ 30.29 |

(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 this table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes and sales dollars, net of blending costs.

Average Realized Sales Prices

Our weighted average sales price was \$40.58/boe for 2017, up \$10.29/boe from \$30.29/boe reported for the year ended December 31, 2016. The increase in our weighted average sales price reflects improved benchmark pricing received for our sales volumes during 2017 relative to 2016.

In Canada, our realized heavy oil sales price averaged \$38.46/bbl which is \$12.00/bbl higher than realized pricing of \$26.46/bbl for 2016. Our Canadian heavy oil production requires blending with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue. We include the cost of blending diluent in our realized heavy oil sales price in order to compare our realized pricing on our produced volumes to the WCS benchmark. The increase in our realized heavy oil sales price for 2017 is a result of the increase in WCS benchmark pricing (expressed in Canadian dollars) which increased by \$11.50/bbl in 2017 relative to 2016.

Our realized Canadian light oil and condensate price averaged \$56.24/bbl for 2017, an increase of \$10.03/bbl from \$46.21/bbl for 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 2016 is consistent with a \$9.91/bbl increase in Edmonton par pricing in 2017.

In the U.S., our realized light oil and condensate price was \$64.17/bbl for the year ended December 31, 2017. This represents an increase of \$13.57/bbl from \$50.60/bbl reported for 2016, slightly higher than a \$11.04/bbl increase in LLS benchmark pricing in 2017 as compared to 2016. Improved contract pricing following the re-negotiation of certain marketing arrangements 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 for 2017. These factors more than offset the impact that a stronger Canadian dollar had on the LLS benchmark expressed in Canadian dollars and our realized pricing in 2017 relative to 2016.

For 2017, our realized NGL price was \$25.86/bbl or 39% of WTI (expressed in Canadian dollars) compared to \$17.16/bbl or 30% of WTI in 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. The increase in our realized price is consistent with an increase in the market prices for propane and butane which have increased relative to WTI in 2017 as compared to 2016.

Our realized natural gas price in Canada was \$2.21/mcf for 2017 compared to realized pricing of \$2.01/mcf in 2016. The increase is a result of higher AECO benchmark pricing in 2017 relative to the comparative year. A portion of our Canadian natural gas sales are referenced to the AECO daily index which was lower throughout 2017 relative to the AECO monthly average index. Accordingly, our realized sales price for 2017 increased by \$0.20/mcf from 2016 relative to a \$0.34/mcf increase in the AECO monthly average over the same periods.

Our U.S. realized natural gas price was \$3.99/mcf in 2017, up from \$3.21/mcf reported for the year ended December 31, 2016. This represents an increase of \$0.78/mcf which is consistent with the increase in the NYMEX natural gas benchmark (expressed in Canadian dollars) in 2017 relative to 2016.

Petroleum and Natural Gas Sales

| (\$ thousands) | Years Ended December 31 | | | | | |
|---------------------------------------|-------------------------|------------|--------------|------------|------------|------------|
| | 2017 | | | 2016 | | |
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Oil sales | | | | | | |
| Heavy oil | \$ 406,569 | \$ — | \$ 406,569 | \$ 238,047 | \$ — | \$ 238,047 |
| Light oil and condensate | 23,876 | 471,997 | 495,873 | 23,792 | 369,869 | 393,661 |
| NGL | 10,664 | 76,234 | 86,898 | 8,287 | 50,416 | 58,703 |
| Total liquids sales | 441,109 | 548,231 | 989,340 | 270,126 | 420,285 | 690,411 |
| Natural gas sales | 29,130 | 73,064 | 102,194 | 29,506 | 60,178 | 89,684 |
| Total petroleum and natural gas sales | 470,239 | 621,295 | 1,091,534 | 299,632 | 480,463 | 780,095 |
| Heavy oil blending expense | (51,012) | — | (51,012) | (9,622) | — | (9,622) |
| Total sales, net of blending expense | \$ 419,227 | \$ 621,295 | \$ 1,040,522 | \$ 290,010 | \$ 480,463 | \$ 770,473 |

Total petroleum and natural gas sales of \$1.1 billion increased \$311.4 million from \$780.1 million reported for 2016. The increase was driven by higher realized pricing in 2017 as production was consistent with the prior year.

In Canada, petroleum and natural gas sales were \$470.2 million for 2017, up 57% from \$299.6 million in 2016. Sales increased as our weighted average realized price in Canada increased 42% from \$24.06/boe in 2016 to \$34.22/boe in 2017, primarily due to the increase in benchmark prices. Annual production of 33,564 boe/d for 2017 is slightly higher than 32,936 boe/d in 2016. The increase in oil and NGL production is a result of the Peace River acquisition and heavy oil drilling in 2017.

Petroleum and natural gas sales of \$621.3 million in the U.S. increased 29% or \$140.8 million from \$480.5 million reported for the year ended December 31, 2016. The increase was driven primarily by a 29% increase in realized pricing of \$46.41/boe for 2017 compared to \$35.89/boe in 2016. Our active capital program and strong well performance more than offset the impact of the sale of our operated Eagle Ford properties in Q3/2016 and weather related downtime in Q3/2017, resulting in average production for 2017 which was relatively consistent with the prior year.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2017 and 2016.

| (\$ thousands except for % and per boe) | Years Ended December 31 | | | | | |
|---|-------------------------|------------|------------|-----------|------------|------------|
| | 2017 | | | 2016 | | |
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Royalties | \$ 58,672 | \$ 183,220 | \$ 241,892 | \$ 37,720 | \$ 140,396 | \$ 178,116 |
| Average royalty rate ⁽¹⁾ | 14.0% | 29.5% | 23.2% | 13.0% | 29.2% | 23.1% |
| Royalty rate per boe | \$ 4.79 | \$ 13.69 | \$ 9.43 | \$ 3.13 | \$ 10.49 | \$ 7.00 |

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending expense.

Total royalties for 2017 were \$241.9 million and averaged 23.2% of petroleum and natural gas sales which is consistent with our annual guidance of approximately 23% of revenue. Our Canadian royalty rate averaged 14.0% of oil and natural gas sales for 2017, up from 13.0% in 2016 as a result of higher commodity prices. In the U.S., royalties for 2017 averaged 29.5% of petroleum and natural gas sales which is fairly consistent with 29.2% for 2016 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage. Total royalties of \$241.9 million for 2017 increased \$63.8 million from 2016 as a result of higher realized pricing in combination with a slight increase in our Canadian royalty rate.

Operating Expense

Years Ended December 31

| (\$ thousands except for per boe) | 2017 | | | 2016 | | |
|-----------------------------------|------------|---------------------|------------|------------|---------------------|------------|
| | Canada | U.S. ⁽¹⁾ | Total | Canada | U.S. ⁽¹⁾ | Total |
| Operating expense | \$ 181,995 | \$ 87,288 | \$ 269,283 | \$ 142,242 | \$ 98,463 | \$ 240,705 |
| Operating expense per boe | \$ 14.86 | \$ 6.52 | \$ 10.50 | \$ 11.80 | \$ 7.36 | \$ 9.46 |

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

Total operating expense was \$269.3 million (\$10.50/boe) for 2017 as compared to \$240.7 million (\$9.46/boe) for 2016 and was in line with our annual guidance of approximately \$10.50/boe for 2017. The increase in operating expense in 2017 was anticipated with higher operating expense in Canada due to the Peace River acquisition in Q1/2017 and with the reactivation of higher operating cost wells that were shut-in for a portion of 2016. Strong production results in Canada and the U.S. along with operating expense reductions on the acquired Peace River properties resulted in reduction to our per unit guidance in 2017 to approximately \$10.50/boe from our original guidance range of \$11.00 - \$12.00/boe.

U.S. operating expense of \$87.3 million (\$6.52/boe) for 2017 was \$11.2 million or \$0.84/boe lower than \$98.5 million (\$7.36/boe) reported for 2016. A general reduction in costs on our non-operated properties combined with the disposition of our operated U.S. properties, which had higher per unit operating costs, resulted in the decrease in U.S. operating expense in 2017 compared to 2016. In 2017, the Canadian dollar strengthened against the U.S. dollar which further reduced our U.S. operating costs expressed in Canadian dollars relative to the prior year.

In Canada, operating expense was \$182.0 million (\$14.86/boe) for 2017, up \$39.8 million or \$3.06/boe from \$142.2 million (\$11.80/boe) from 2016. We anticipated an increase to Canadian operating costs following the Q1/2017 acquisition of Peace River properties which have higher per unit operating costs than our other properties combined with the reactivation of higher cost production that was shut-in for a portion of 2016. We have been able to mitigate some of these expected increases by reducing costs on the acquired Peace River properties and from continued cost saving initiatives.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of heavy oil in Canada to pipeline and rail terminals. The following table compares our transportation expense for the years ended December 31, 2017 and 2016.

Years Ended December 31

| (\$ thousands except for per boe) | 2017 | | | 2016 | | |
|-----------------------------------|-----------|---------------------|-----------|-----------|---------------------|-----------|
| | Canada | U.S. ⁽¹⁾ | Total | Canada | U.S. ⁽¹⁾ | Total |
| Transportation expense | \$ 33,985 | \$ — | \$ 33,985 | \$ 28,257 | \$ — | \$ 28,257 |
| Transportation expense per boe | \$ 2.77 | \$ — | \$ 1.33 | \$ 2.34 | \$ — | \$ 1.11 |

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

Transportation expense was \$34.0 million (\$2.77/boe) for 2017, up by \$5.7 million or 20.3% as compared to \$28.3 million (\$2.34/boe) for 2016. An increase in trucking volumes and distances along with the Q1/2017 Peace River acquisition has resulted in higher transportation expense in 2017 relative to 2016. Transportation expense of \$1.33/boe for 2017 was slightly below our annual guidance of approximately \$1.40/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 sales price received for the blended product is recorded as heavy oil revenue. Our heavy oil blending expense is netted against our heavy oil revenue to compare the realized price on our produced volumes to benchmark pricing. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantities and price of blending diluent required to meet pipeline specifications.

Blending expense for 2017 was \$51.0 million compared to \$9.6 million for 2016. The \$41.4 million increase in blending expense during 2017 is due to additional blending diluent purchases associated with 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 2016.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. 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 year ended December 31, 2017 and 2016.

| (\$ thousands) | Years Ended December 31 | | |
|--|-------------------------|--------------|-------------|
| | 2017 | 2016 | Change |
| Realized financial derivatives gain (loss) | | | |
| Crude oil | \$ 4,552 | \$ 88,860 | \$ (84,308) |
| Natural gas | 3,064 | 8,069 | (5,005) |
| Total | \$ 7,616 | \$ 96,929 | \$ (89,313) |
| Unrealized financial derivatives gain (loss) | | | |
| Crude oil | \$ (16,841) | \$ (122,249) | \$ 105,408 |
| Natural gas | 14,402 | (17,887) | 32,289 |
| Total | \$ (2,439) | \$ (140,136) | \$ 137,697 |
| Total financial derivatives gain (loss) | | | |
| Crude oil | \$ (12,289) | \$ (33,389) | \$ 21,100 |
| Natural gas | 17,466 | (9,818) | 27,284 |
| Total | \$ 5,177 | \$ (43,207) | \$ 48,384 |

The realized financial derivatives gain of \$7.6 million for 2017 is a result of crude oil and natural gas market price indexes settling at levels below those set in our fixed price contracts. During 2017, we recorded realized gains of \$3.1 million on our natural gas financial derivatives. These gains were primarily a result of the AECO price index for 2017 averaging lower than the fixed price of \$2.85/GJ on 22,500 GJ/d of AECO contracts in place for 2017. Realized gains of \$4.6 million related to our crude oil financial derivatives in place for 2017 were driven by \$5.8 million of gains on 3,500 bbl/d of swap contracts with a fixed price of US\$54.46/bbl and \$2.5 million of gains on outstanding 3-way options where the market price of WTI settled below the purchased put price in certain months. These gains on WTI-based crude oil hedges were offset by \$3.7 million of realized losses on WCS differential financial derivatives as the index settled below the prices set in our contracts throughout the year.

At December 31, 2017, the fair value of our financial derivative contracts represent a net liability of \$31.6 million compared to a net liability of \$29.1 million at December 31, 2016. The net liability of \$31.6 million as at December 31, 2017 is primarily a result of futures pricing for crude oil indexes being higher than the prices set in our fixed price crude oil financial derivatives in place for 2018.

We had the following commodity financial derivative contracts as at March 5, 2018.

| | Period | Volume | Price/Unit ⁽¹⁾ | Index |
|-----------------------------|----------------------|----------------|-------------------------------|-------|
| Oil | | | | |
| 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 | 6,000 bbl/d | WTI less US\$14.24/bbl | WCS |
| Fixed - Sell | Jan 2018 to Dec 2018 | 13,000 bbl/d | US\$51.64/bbl | WTI |
| 3-way option ⁽²⁾ | Jan 2018 to Dec 2018 | 2,000 bbl/d | US\$60.00/US\$54.40/US\$40.00 | WTI |
| Fixed - Sell | Jan 2018 to Dec 2018 | 4,000 bbl/d | US\$61.31/bbl | Brent |
| Fixed - Sell | Feb 2018 to Dec 2018 | 1,000 bbl/d | US\$61.04/bbl | WTI |
| Swaption ⁽³⁾ | Jan 2019 to Dec 2019 | 2,000 bbl/d | US\$59.60/bbl | WTI |
| 3-way option ⁽²⁾ | Jan 2019 to Dec 2019 | 2,000 bbl/d | US\$70.00/US\$60.00/US\$50.00 | WTI |
| 3-way option ⁽²⁾ | Jan 2019 to Dec 2019 | 1,000 bbl/d | US\$75.50/US\$65.50/US\$55.50 | Brent |
| Natural Gas | | | | |
| Fixed - Sell | Jan 2018 to Dec 2018 | 10,000 mmbtu/d | US\$3.03 | NYMEX |
| Fixed - Sell | Jan 2018 to Dec 2018 | 5,000 GJ/d | \$2.67 | AECO |
| Fixed - Sell | Feb 2018 to Dec 2018 | 5,000 mmbtu/d | US\$2.99 | NYMEX |

(1) Based on the weighted average price per unit for the period.

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US\$60/US\$54.40/US\$40 contract, Baytex receives WTI plus US\$14.40/bbl when WTI is at or below US\$40/bbl; Baytex receives US\$54.40/bbl when WTI is between US\$40/bbl and US\$54.40/bbl; Baytex receives the market price when WTI is between US\$54.40/bbl and US\$60/bbl; and Baytex receives US\$60/bbl when WTI is above US\$60/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the years ended December 31, 2017 and 2016.

| | Years Ended December 31 | | | | | |
|--|-------------------------|----------|----------|----------|----------|----------|
| | 2017 | | | 2016 | | |
| (\$ per boe except for volume) | Canada | U.S. | Total | Canada | U.S. | Total |
| Sales volume (boe/d) | 33,564 | 36,678 | 70,242 | 32,936 | 36,573 | 69,509 |
| Operating netback: | | | | | | |
| Total sales, net of blending expense | \$ 34.22 | \$ 46.41 | \$ 40.58 | \$ 24.06 | \$ 35.89 | \$ 30.29 |
| Less: | | | | | | |
| Royalties | 4.79 | 13.69 | 9.43 | 3.13 | 10.49 | 7.00 |
| Operating expenses | 14.86 | 6.52 | 10.50 | 11.80 | 7.36 | 9.46 |
| Transportation expenses | 2.77 | — | 1.33 | 2.34 | — | 1.11 |
| Operating netback | \$ 11.80 | \$ 26.20 | \$ 19.32 | \$ 6.79 | \$ 18.04 | \$ 12.72 |
| Realized financial derivatives gain | — | — | 0.30 | — | — | 3.81 |
| Operating netback after financial derivatives gain | \$ 11.80 | \$ 26.20 | \$ 19.62 | \$ 6.79 | \$ 18.04 | \$ 16.53 |

Operating netback after financial derivatives increased by \$3.09/boe to \$19.62/boe reported for 2017 from \$16.53/boe for 2016. The increase in our realized sales price per boe during 2017 was offset partially by higher royalties, operating expenses and transportation expenses compared to 2016. The increase in operating and transportation expenses per boe in the current period was driven by higher operating cost properties which were shut-in for a portion of 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 year 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. Exploration and evaluation expense was \$8.3 million for 2017 compared to \$6.0 million for 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 years ended December 31, 2017 and 2016.

| (\$ thousands except for per boe) | Years Ended December 31 | | | | | |
|---|-------------------------|------------|------------|------------|------------|------------|
| | 2017 | | | 2016 | | |
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Depletion and depreciation ⁽¹⁾ | \$ 200,996 | \$ 280,933 | \$ 481,929 | \$ 215,078 | \$ 293,231 | \$ 508,309 |
| Depletion and depreciation per boe | \$ 16.41 | \$ 20.98 | \$ 18.80 | \$ 17.49 | \$ 22.03 | \$ 20.04 |

(1) Canada includes corporate depreciation.

Depletion and depreciation expense was \$481.9 million (\$18.80/boe) for 2017 compared to \$508.3 million (\$20.04/boe) reported for 2016. In Canada, depletion expense was lower in 2017 compared to 2016 primarily due to impairments recorded in Q4/2016 which reduced the carrying value and the depletion rate for certain Canadian properties. The U.S. depletion rate for 2017 is lower than the comparative period due to a lower average CAD/USD exchange rate in 2017 relative to 2016 combined with higher proved plus probable reserve volumes in 2017.

Impairment

In 2017, we did not identify any indicators of impairment or impairment reversal on any of our cash generating units ("CGU") and therefore did not record any impairment expense or reversals of previously recorded impairments during the year.

During 2016, we recorded total impairment expense of \$423.3 million related to the de-recognition of E&E assets in the Eagle Ford and the write-down of oil and gas properties in Peace River and Lloydminster. An impairment charge of \$166.6 million was recorded for the de-recognition of E&E assets in the Eagle Ford after changes in our development plan resulted in possible reserves being reclassified to contingent resources. We also recorded a \$230.0 million impairment of oil and gas properties in our Peace River CGU associated with a decline in proved plus probable reserves due to the lower commodity price environment combined with reduced activity levels throughout 2016. In Q3/2016, we recorded a \$26.6 million write-down on certain oil and gas properties in our Lloydminster CGU prior to their disposition in Q4/2016.

General and Administrative Expense

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs, and administrative recoveries earned for operating capital and production activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated capital and production activity during the period.

The following table summarizes our G&A expenses for the years ended December 31, 2017 and 2016.

| (\$ thousands except for per boe) | Years Ended December 31 | | |
|--|-------------------------|-----------|------------|
| | 2017 | 2016 | Change |
| General and administrative expense | \$ 47,389 | \$ 50,866 | \$ (3,477) |
| General and administrative expense per boe | \$ 1.85 | \$ 2.00 | \$ (0.15) |

We reported G&A expense of \$47.4 million or \$1.85/boe for the year ended December 31, 2017 compared to \$50.9 million or \$2.00/boe for 2016. Reduced staffing levels and our ongoing cost savings efforts have resulted in lower G&A expense in 2017 relative to the comparative period. Overhead recoveries were also higher during 2017 due to increased capital activity in Canada relative to 2016, which helped reduce G&A expense compared to 2016. When combined with average production that exceeded the high end of our annual guidance range, per unit G&A expense for the year ended December 31, 2017 was below our annual guidance of approximately \$2.00/boe.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense associated with the Share Award Incentive Plan is recognized in net income or 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 \$15.5 million for 2017 which is up from \$13.9 million reported for 2016. SBC expense is higher in 2017 due to a higher grant date fair value assigned to share awards granted in 2017 as compared to units granted in 2016.

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 \$113.6 million for 2017 which is consistent with \$114.2 million reported for 2016. Cash interest expense of \$100.5 million was down \$3.2 million from 2016 due to lower interest on our long-term notes due to a strengthening Canadian dollar which reduced the amount of interest reported in Canadian dollars. This was offset by a \$2.6 million increase in our non-cash interest primarily due to an increase in accretion expense related to our asset retirement obligations.

Foreign Exchange

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

| | Years Ended December 31 | | |
|---|-------------------------|-------------|----------|
| <i>(\$ thousands except for exchange rates)</i> | 2017 | 2016 | Change |
| Unrealized foreign exchange gain | \$ (86,649) | \$ (41,436) | (45,213) |
| Realized foreign exchange gain | (411) | (1,242) | 831 |
| Foreign exchange gain | \$ (87,060) | \$ (42,678) | (44,382) |
| CAD/USD exchange rates: | | | |
| At beginning of period | 1.3427 | 1.3840 | |
| At end of period | 1.2518 | 1.3427 | |

We recorded an unrealized foreign exchange gain of \$86.6 million for 2017 due to a strengthening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.2518 as at December 31, 2017 compared to 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 for our Canadian operations. We recorded realized foreign exchange gains of \$0.4 million for the year ended December 31, 2017 compared to gains of \$1.2 million for 2016.

Income Taxes

| | Years Ended December 31 | | |
|------------------------------|-------------------------|--------------|---------|
| <i>(\$ thousands)</i> | 2017 | 2016 | Change |
| Current income tax recovery | \$ (1,085) | \$ (8,042) | 6,957 |
| Deferred income tax recovery | (155,343) | (264,561) | 109,218 |
| Total income tax recovery | \$ (156,428) | \$ (272,603) | 116,175 |

The current income tax recovery was \$1.1 million for 2017, as compared to \$8.0 million for 2016. These current income tax recoveries relate to income tax losses that were incurred in 2017 and 2016, which have been used to recover a portion of income taxes paid in previous years.

The 2017 deferred income tax recovery of \$155.3 million decreased \$109.2 million from \$264.6 million in 2016. The deferred income tax recovery for 2017 is lower compared to 2016 primarily due to lower deferred tax recoveries related to impairment of our Canadian and U.S. properties recorded in 2016. Deferred taxes for 2017 was also impacted by lower unrealized losses recorded on our financial derivatives contracts along with U.S. tax reform. On December 22, 2017, the United States of America enacted the Tax Cuts and Jobs Act which altered the federal income tax law that applies to our U.S. subsidiary. The most significant changes include a reduction of the statutory income tax rate to 21% from 35%, which resulted in a \$91.8 million deferred tax recovery recorded for the year ended December 31, 2017.

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

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

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

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

Tax Pools

The Company has Canadian and U.S. tax pools, which are available to reduce future taxable income. Our cash income tax liability is dependent upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and currently enacted tax laws in Canada and the United States, we do not expect to pay material amounts of cash income taxes prior to 2022.

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

| <i>(\$ thousands)</i> | December 31, 2017 | December 31, 2016 |
|--|--------------------------|---------------------|
| Canadian Tax Pools | | |
| Canadian oil and natural gas property expenditures | \$ 308,366 | \$ 198,525 |
| Canadian development expenditures | 176,188 | 250,239 |
| Canadian exploration expenditures | 1,343 | 210 |
| Undepreciated capital costs | 228,739 | 256,549 |
| Non-capital losses | 337,808 | 151,959 |
| Financing costs and other | 46,986 | 69,025 |
| Total Canadian tax pools | \$ 1,099,430 | \$ 926,507 |
| U.S. Tax Pools | | |
| Depletion | \$ 183,406 | \$ 297,252 |
| Intangible drilling costs | 204,857 | 388,727 |
| Tangibles | 108,631 | 136,969 |
| Non-capital losses | 1,140,673 | 1,039,782 |
| Other | 303,357 | 201,896 |
| Total U.S. tax pools | \$ 1,940,924 | \$ 2,064,626 |

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income (loss) for the years ended December 31, 2017 and 2016 are set forth in the following table.

| (\$ thousands) | Years Ended December 31 | | |
|---|-------------------------|--------------|------------|
| | 2017 | 2016 | Change |
| Petroleum and natural gas sales | \$ 1,091,534 | \$ 780,095 | \$ 311,439 |
| Royalties | (241,892) | (178,116) | (63,776) |
| Revenue, net of royalties | 849,642 | 601,979 | 247,663 |
| Expenses | | | |
| Operating | (269,283) | (240,705) | (28,578) |
| Transportation | (33,985) | (28,257) | (5,728) |
| Blending | (51,012) | (9,622) | (41,390) |
| Operating netback | \$ 495,362 | \$ 323,395 | \$ 171,967 |
| General and administrative | (47,389) | (50,866) | 3,477 |
| Financing and interest | (100,482) | (103,685) | 3,203 |
| Realized financial derivatives gain | 7,616 | 96,929 | (89,313) |
| Realized foreign exchange gain | 411 | 1,242 | (831) |
| Other (expense) income | (2,216) | 1,964 | (4,180) |
| Current income tax recovery | 1,085 | 8,042 | (6,957) |
| Payments on onerous contracts | (6,746) | (770) | (5,976) |
| Adjusted funds flow | \$ 347,641 | \$ 276,251 | \$ 71,390 |
| Exploration and evaluation | (8,253) | (5,976) | (2,277) |
| Depletion and depreciation | (481,929) | (508,309) | 26,380 |
| Share based compensation | (15,509) | (13,882) | (1,627) |
| Non-cash financing and accretion | (13,156) | (10,514) | (2,642) |
| Unrealized financial derivatives loss | (2,439) | (140,136) | 137,697 |
| Unrealized foreign exchange gain | 86,649 | 41,436 | 45,213 |
| Gain on disposition of oil and gas properties | 12,081 | 43,907 | (31,826) |
| Impairment | — | (423,176) | 423,176 |
| Deferred income tax recovery | 155,343 | 264,561 | (109,218) |
| Non-cash other expense | — | (10,116) | 10,116 |
| Payments on onerous contracts | 6,746 | 770 | 5,976 |
| Net income (loss) for the period | \$ 87,174 | \$ (485,184) | \$ 572,358 |

We generated adjusted funds flow of \$347.6 million for 2017, an increase of \$71.4 million from adjusted funds flow of \$276.3 million reported for 2016. The increase in adjusted funds flow in 2017 was primarily due to higher operating netback which increased \$172.0 million from 2016 due to higher commodity prices which increased revenues, slightly offset by higher royalties, operating and transportation expenses. The increase in operating netback was offset by a decrease in hedging gains of \$89.3 million along with a reduction of approximately \$17.1 million in adjusted funds flow from a combination of increased payments on onerous contracts, other expenses and a smaller tax recovery.

In 2017, net income was \$87.2 million compared to a net loss of \$485.2 million in 2016. Net income increased \$572.4 million in 2017 compared to 2016 mainly due to impairment of \$423.2 million reported in 2016 compared to no impairment being recorded in 2017. Our unrealized financial derivative losses decreased \$137.7 million and our unrealized gain on foreign exchange was \$45.2 million higher in 2017 compared to 2016. This was offset by a reduction of \$109.2 million in the deferred income tax recovery in 2017, which was larger in 2016 due to the impairment losses recorded.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The \$166.8 million foreign currency translation loss for 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. The CAD/USD exchange rate was 1.2518 as at December 31, 2017 compared to 1.3427 as at December 31, 2016.

Capital Expenditures

Capital expenditures for the years ended December 31, 2017 and 2016 are summarized as follows.

| (\$ thousands except for # of wells drilled) | 2017 | | | 2016 | | |
|---|------------|------------|------------|-----------|------------|------------|
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Land and seismic | \$ 4,613 | \$ 1,153 | \$ 5,766 | \$ 4,691 | \$ 6,098 | \$ 10,789 |
| Drilling, completion and equipping | 81,564 | 199,849 | 281,413 | 13,618 | 178,412 | 192,030 |
| Facilities | 27,097 | 11,990 | 39,087 | 7,564 | 14,400 | 21,964 |
| Total exploration and development | \$ 113,274 | \$ 212,992 | \$ 326,266 | \$ 25,873 | \$ 198,910 | \$ 224,783 |
| Total acquisitions, net of proceeds from divestitures | 59,857 | — | 59,857 | (8,883) | (54,237) | (63,120) |
| Total oil and natural gas expenditures | \$ 173,131 | \$ 212,992 | \$ 386,123 | \$ 16,990 | \$ 144,673 | \$ 161,663 |
| Wells drilled (net) | 53.8 | 32.8 | 86.6 | 4.0 | 36.9 | 40.9 |

We invested \$326.3 million on exploration and development activities during 2017 which is \$101.5 million higher than exploration and development expenditures of \$224.8 million for 2016. Our capital program was focused on our high return assets in the Eagle Ford and accelerating activity on our heavy oil properties in Canada after an improvement in commodity prices from 2017.

In Canada, we initiated an operated drilling program in Q4/2016 and adjusted the pace of development as the outlook for commodity prices fluctuated throughout 2017. Total exploration and development expenditures in Canada were \$113.3 million, up from \$25.9 million in 2016 reflecting the deferral of all operated heavy oil drilling activity during the first nine months of 2016. We drilled 86 (53.8 net) wells and incurred drilling, completion and equipping costs of \$81.6 million during 2017 compared to drilling 15 (4.0 net) wells during 2016 for \$13.6 million. In Peace River, our cost savings initiatives have resulted in drill, completion and equipping costs of \$2.5 million for operated wells drilled during 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. During 2017, we initiate the construction of a gas plant and invested in strategic infrastructure projects including pipeline expansions which will support growth in our expanded position in Peace River.

In the U.S., capital spending increased to \$213.0 million in 2017 from \$198.9 million in 2016 due to higher drilling and completion activity levels relative to 2016. In Q4/2016, we increased the pace of development on our Eagle Ford property and averaged 4 drilling crews and 2 completion crews on our lands throughout the year. We participated in the drilling of 140 (32.8 net) wells and initiated production from 115 (28.7 net) wells during 2017 compared to 36.9 net wells drilled and 36.3 net wells on production in 2016.

Acquisitions, net of divestitures, totaled \$59.9 million for the year ended December 31, 2017 compared to net dispositions of \$63.1 million in 2016. The acquisitions in 2017 includes the Q1/2017 Peace River acquisition for consideration of \$66.1 million, net of minor dispositions throughout the year. Disposition activity in 2016 included the \$54.2 million disposition of our operated assets in the Eagle Ford along with minor non-core dispositions in Canada.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions and the risk characteristics of our oil and gas properties. At December 31, 2017, our capital structure was comprised of shareholders' capital, long-term debt, working capital and our bank loan.

The capital intensive nature of our operations requires the Company to maintain adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures. The Company's adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term growth. At December 31, 2017, net debt was \$1,734.3 million, a decrease of \$39.2 million from \$1,773.5 million at December 31, 2016. Adjusted funds flow for 2017 exceeded exploration and development expenditures and settlements of asset retirement obligations by \$7.9 million which resulted in a reduction of net debt. The strengthening of the Canadian dollar reduced the reported amount of our U.S. dollar denominated debt at December 31, 2017 which more than offset the increase in net debt due to the \$66.1 million Peace River acquisition which closed on January 20, 2017.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio. At December 31, 2017, our net debt to adjusted funds flow ratio was 5.0 compared to a ratio of 6.4 as at December 31, 2016. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2016 is attributed to higher adjusted funds flow from improved commodity prices and higher annual production in 2017, along with a decrease in net debt as at December 31, 2017.

Bank Loan

The revolving extendible secured credit facilities are comprised of a US\$25 million operating loan, 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 including the financial covenants 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 2017 was 4.1% as compared to 3.5% for 2016.

Covenants

On March 31, 2016, we amended our credit facilities and restructured the financial covenants applicable to the Revolving Facilities. The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at December 31, 2017.

| Covenant Description | Position as at December 31, 2017 | Ratio for the Quarter(s) ending: | | | |
|--|----------------------------------|-------------------------------------|-------------------------------------|-------------------|------------|
| | | December 31, 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) | 0.50:1.00 | 5.00:1.00 | 4.50:1.00 | 4.00:1.00 | 3.50:1.00 |
| Interest Coverage ⁽³⁾ (Minimum Ratio) | 4.54:1.00 | 1.25:1.00 | 1.50:1.00 | 1.75:1.00 | 2.00:1.00 |

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2017, the Company's Senior Secured Debt totaled \$228 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2017 was \$454 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2017 were \$100 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 four series of long-term notes outstanding that total \$1.49 billion as at December 31, 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 December 31, 2017, the fixed charge coverage ratio was 4.54:1.00.

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 "5.125% Notes") and US\$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2017, the 5.125% Notes are redeemable at our option, in whole or in part, at specified redemption prices. The 5.625% Notes are redeemable at our option, in whole or in part, commencing on June 1, 2019 at specified redemption prices.

On July 13, 2017, we redeemed the remaining US\$6.4 million principal amount of 7.5% senior unsecured notes assumed pursuant to the acquisition of Aurora Oil & Gas Limited on June 11, 2014.

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 year ended December 31, 2017, we issued 2.0 million common shares pursuant to our share-based compensation program. As at March 5, 2018, we had 236.6 million common shares issued and outstanding 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 adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 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 | \$ 144,542 | \$ 144,542 | \$ — | \$ — | \$ — |
| Bank loan ^{(1) (2)} | 213,376 | — | 213,376 | — | — |
| Long-term notes ⁽²⁾ | 1,489,210 | — | — | 988,490 | 500,720 |
| Interest on long-term notes ⁽³⁾ | 398,635 | 86,377 | 172,754 | 99,609 | 39,895 |
| Operating leases | 29,926 | 7,727 | 13,510 | 8,689 | — |
| Processing agreements | 41,845 | 6,993 | 9,164 | 9,004 | 16,684 |
| Transportation agreements | 31,948 | 2,602 | 14,635 | 13,661 | 1,050 |
| Total | \$ 2,349,482 | \$ 248,241 | \$ 423,439 | \$ 1,119,453 | \$ 558,349 |

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

(2) Principal amount of instruments.

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

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

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

| <i>(\$ thousands, except per common share amounts)</i> | 2017 | 2016 | 2015 |
|---|---------------------|--------------|----------------|
| Revenues, net of royalties | \$ 849,642 | \$ 601,979 | \$ 879,999 |
| Adjusted funds flow | \$ 347,641 | \$ 276,251 | \$ 516,417 |
| Per common share - basic | \$ 1.48 | \$ 1.30 | \$ 2.67 |
| Per common share - diluted | \$ 1.47 | \$ 1.30 | \$ 2.67 |
| Net income (loss) | \$ 87,174 | \$ (485,184) | \$ (1,142,880) |
| Per common share - basic | \$ 0.37 | \$ (2.29) | \$ (5.77) |
| Per common share - diluted | \$ 0.37 | \$ (2.29) | \$ (5.77) |
| Total assets | \$ 4,372,111 | \$ 4,594,085 | \$ 5,488,498 |
| Bank loan - principal | \$ 213,376 | \$ 191,286 | \$ 256,749 |
| Long term notes - principal | \$ 1,489,210 | \$ 1,584,158 | \$ 1,623,658 |
| Cash dividends or distributions declared per common share | \$ — | \$ — | \$ 0.80 |
| Average wellhead prices, net of blending costs (\$/boe) | \$ 40.58 | \$ 30.29 | \$ 35.40 |
| Total production (boe/d) | 70,242 | 69,509 | 84,648 |

QUARTERLY FINANCIAL INFORMATION

| (\$ thousands, except per common share amounts) | 2017 | | | | 2016 | | | |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Petroleum and natural gas sales | 302,186 | 254,430 | 274,369 | 260,549 | 233,116 | 197,648 | 195,733 | 153,598 |
| Net income (loss) | 76,038 | (9,228) | 9,268 | 11,096 | (359,424) | (39,430) | (86,937) | 607 |
| Per common share - basic | 0.32 | (0.04) | 0.04 | 0.05 | (1.66) | (0.19) | (0.41) | — |
| Per common share - diluted | 0.32 | (0.04) | 0.04 | 0.05 | (1.66) | (0.19) | (0.41) | — |
| Adjusted funds flow | 105,796 | 77,340 | 83,136 | 81,369 | 77,239 | 72,106 | 81,261 | 45,645 |
| Per common share - basic | 0.45 | 0.33 | 0.35 | 0.35 | 0.36 | 0.34 | 0.39 | 0.22 |
| Per common share - diluted | 0.44 | 0.33 | 0.35 | 0.34 | 0.36 | 0.34 | 0.39 | 0.22 |
| Exploration and development | 90,156 | 61,544 | 78,007 | 96,559 | 68,029 | 39,579 | 35,490 | 81,685 |
| Canada | 41,864 | 14,487 | 18,439 | 38,484 | 12,151 | 6,120 | 2,747 | 4,855 |
| U.S. | 48,292 | 47,057 | 59,568 | 58,075 | 55,878 | 33,459 | 32,743 | 76,830 |
| Acquisitions, net of divestitures | (3,937) | (7,436) | 5,226 | 66,004 | (322) | (62,752) | (37) | (9) |
| Net debt | 1,734,284 | 1,748,805 | 1,819,387 | 1,850,909 | 1,773,541 | 1,864,022 | 1,942,538 | 1,981,343 |
| Total assets | 4,372,111 | 4,353,637 | 4,582,049 | 4,702,423 | 4,594,085 | 4,995,876 | 5,089,280 | 5,197,913 |
| Common shares outstanding | 235,451 | 235,451 | 234,204 | 234,203 | 233,449 | 211,542 | 210,715 | 210,689 |
| Daily production | | | | | | | | |
| Total production (boe/d) | 69,556 | 69,310 | 72,812 | 69,298 | 65,136 | 67,167 | 70,031 | 75,776 |
| Canada (boe/d) | 32,194 | 34,560 | 34,284 | 33,217 | 31,704 | 33,615 | 31,722 | 34,709 |
| U.S. (boe/d) | 37,362 | 34,750 | 38,528 | 36,081 | 33,432 | 33,552 | 38,309 | 41,067 |
| Benchmark prices | | | | | | | | |
| WTI oil (US\$/bbl) | 55.40 | 48.20 | 48.28 | 51.91 | 49.29 | 44.94 | 45.60 | 33.45 |
| WCS heavy (US\$/bbl) | 43.14 | 38.26 | 37.16 | 37.34 | 34.97 | 31.44 | 32.29 | 19.22 |
| CAD/USD avg exchange rate | 1.2717 | 1.2524 | 1.3447 | 1.3229 | 1.3339 | 1.3051 | 1.2885 | 1.3748 |
| AECO gas (\$/mcf) | 1.96 | 2.04 | 2.77 | 2.94 | 2.81 | 2.20 | 1.25 | 2.11 |
| NYMEX gas (US\$/mmbtu) | 2.93 | 3.00 | 3.18 | 3.32 | 2.98 | 2.81 | 1.95 | 2.09 |
| Sales price (\$/boe) | 44.75 | 38.04 | 39.41 | 40.16 | 38.16 | 31.73 | 30.52 | 21.93 |
| Royalties (\$/boe) | 10.86 | 8.65 | 9.06 | 9.17 | 9.28 | 7.37 | 6.65 | 5.02 |
| Operating expense (\$/boe) | 10.91 | 10.10 | 10.70 | 10.28 | 9.96 | 9.07 | 8.67 | 10.11 |
| Transportation expense (\$/boe) | 1.20 | 1.46 | 1.35 | 1.29 | 1.30 | 1.38 | 0.81 | 0.98 |
| Operating netback (\$/boe) | 21.78 | 17.83 | 18.30 | 19.42 | 17.62 | 13.91 | 14.39 | 5.82 |
| Financial derivatives gain (\$/boe) | 0.30 | 0.44 | 0.40 | 0.04 | 1.62 | 3.04 | 3.74 | 6.47 |
| Operating netback after financial derivatives (\$/boe) | 22.08 | 18.27 | 18.70 | 19.46 | 19.24 | 16.95 | 18.13 | 12.29 |

Our operating and financial results have improved as oil prices continue to recover from the multi-year lows experienced in early 2016. Compliance with OPEC's production quotas and increased global demand for crude oil have resulted in the WTI benchmark gradually increasing from US\$33.45/bbl in Q1/2016 to US\$55.40/bbl in Q4/2017. We increased our capital activity in Canada and the U.S. in Q4/2016 as the outlook for oil price improved after reducing capital activity in response to the low commodity price environment. Our exploration and development expenditures continue to be focused on our Eagle Ford properties as these assets generate our highest netbacks and rates of return. In Canada, exploration and development activity was higher in 2017 after deferring operated heavy oil drilling during the first nine months of 2016. The increased level of activity has increased production in 2017 from, after dispositions completed in 2016 and lower capital investment resulted in declining quarterly production through the end of 2016. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved in 2017 as commodity prices recovered and our daily production increased from 2016. Net debt has decreased from \$2.0 billion at Q1/2016 to \$1.7 billion at Q4/2017 primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar which has decreased the reported amount of our U.S. dollar denominated debt.

FOURTH QUARTER OF 2017

We delivered strong operating and financial results in Q4/2017. Production averaged 69,556 boe/d in Q4/2017 and contributed to our annual production of 70,242 boe/d which exceeded the high end of our annual guidance range of 69,500-70,000 boe/d. Average daily production in Q4/2017 was 7% higher than 65,136 boe/d reported for Q4/2016 due to our successful 2017 capital program and strong production results. Adjusted funds flow of \$105.8 million for Q4/2017 increased relative to \$77.2 million in Q4/2016 as a result of our solid operating results and an improvement in commodity prices.

In the Eagle Ford, production averaged 37,362 boe/d in Q4/2017 which is an increase of 12% from 33,432 boe/d in Q4/2016. Continued strong well results from enhanced completion techniques resulted in higher initial production rates from wells that commenced production in 2017 compared to 2016 which contributed to the higher average production relative to Q4/2016. In addition, the pace of development slowed in Q2/2016 and Q3/2016 which contributed to a decline in production in the last half of 2016 before the pace of development increased again in Q4/2016. Capital expenditures in the Eagle Ford were \$48.3 million in Q4/2017 as we maintained the pace of development and drilled 37 (7.6 net) wells and placed 25 (5.4 net) wells on production during the quarter.

In Canada, production for Q4/2017 averaged 32,194 boe/d which is 2% higher than 31,704 boe/d in Q4/2016. The acquisition of the Peace River properties in Q1/2017 along with the positive well results from our 2017 capital program contributed to the increased production which offset natural declines. Capital expenditures were \$41.9 million in Q4/2017 and included \$24.6 million on drilling and completion costs for 26 (13.4 net) wells and \$15.3 million on pipelines and facilities which included initial costs for construction of a gas plant which will support growth in our expanded position in Peace River.

Operating netback per boe increased to \$21.78/boe for Q4/2017 from \$17.62/boe in Q4/2016 primarily due to the increase in commodity prices. The WTI benchmark price averaged US\$55.40/bbl in Q4/2017 compared to US\$49.29/bbl in 2016 and the LLS benchmark increased to US\$60.50/bbl in Q4/2017 compared to US\$49.95/bbl in Q4/2016. The increase in oil prices increased our realized sales price, net of blending by \$6.59/boe which was offset by higher royalties per boe and an increase in operating costs per boe from the Q1/2017 Peace River acquisition and from the reactivation of higher operating costs wells that were shut-in for a portion of 2016.

We generated adjusted funds flow of \$105.8 million in Q4/2017 which is \$28.6 million higher than \$77.2 million in Q4/2016. The increase relative to Q4/2016 was primarily driven by higher commodity prices and average daily production in Q4/2017 relative to the comparative period. The increase in total sales, net of blending in was offset by higher royalties associated with higher revenues and higher operating costs from the additional production volumes. Higher operating netback in Q4/2017 was offset by smaller hedging gains and certain other expenses relative to the fourth quarter of 2016 and resulted in a \$28.6 million increase in adjusted funds flow.

We recorded net income of \$76.0 million in Q4/2017 compared to a net loss of \$359.4 million in Q4/2016. The change in net income is primarily related to \$396.6 million of impairment expense recorded in Q4/2016 as compared to no impairment expense recorded during 2017. The change in net income was also due to lower foreign exchange gains and lower gains on disposition of oil and gas properties in Q4/2017 relative to the comparative period.

The following table provides select operating results for Q4/2017.

| | Three Months Ended December 31 | | | | | |
|---|--------------------------------|-----------|------------|-----------|-----------|-----------|
| | 2017 | | | 2016 | | |
| <i>(\$ thousands, except as noted)</i> | Canada | U.S. | Total | Canada | U.S. | Total |
| Daily Production | | | | | | |
| Heavy oil (bbl/d) | 24,945 | — | 24,945 | 22,982 | — | 22,982 |
| Light oil and condensate (bbl/d) | 882 | 20,347 | 21,229 | 1,281 | 18,882 | 20,163 |
| NGL (bbl/d) | 987 | 8,885 | 9,872 | 1,307 | 7,012 | 8,319 |
| Natural gas (mcf/d) | 32,284 | 48,779 | 81,063 | 36,804 | 45,228 | 82,032 |
| Total production (boe/d) | 32,194 | 37,362 | 69,556 | 31,704 | 33,432 | 65,136 |
| Baytex Average Sales Prices | | | | | | |
| Canadian heavy oil (\$/bbl) ⁽¹⁾ | \$ 42.03 | \$ — | \$ 42.03 | \$ 34.33 | \$ — | \$ 34.33 |
| Light oil and condensate (\$/bbl) | 62.47 | 73.08 | 72.64 | 55.16 | 60.45 | 60.12 |
| NGL (\$/bbl) | 28.89 | 29.16 | 29.14 | 18.50 | 23.41 | 22.64 |
| Natural gas (\$/mcf) | 1.72 | 3.67 | 2.89 | 2.78 | 4.28 | 3.61 |
| Weighted average (\$/boe) ⁽²⁾ | \$ 36.89 | \$ 51.53 | \$ 44.75 | \$ 31.10 | \$ 44.84 | \$ 38.16 |
| Operating netback (\$/boe) | | | | | | |
| Sales, net of blending expense | \$ 36.89 | \$ 51.53 | \$ 44.75 | \$ 31.10 | \$ 44.84 | \$ 38.16 |
| Less: | | | | | | |
| Royalties | 5.72 | 15.30 | 10.86 | 4.82 | 13.52 | 9.28 |
| Operating expenses | 16.57 | 6.04 | 10.91 | 13.10 | 6.98 | 9.96 |
| Transportation expenses | 2.59 | — | 1.20 | 2.67 | — | 1.30 |
| Operating netback | \$ 12.01 | \$ 30.19 | \$ 21.78 | \$ 10.51 | \$ 24.34 | \$ 17.62 |
| Financial derivatives gain | \$ — | \$ — | \$ 0.30 | \$ — | \$ — | \$ 1.62 |
| Operating netback after financial derivatives | \$ 12.01 | \$ 30.19 | \$ 22.08 | \$ 10.51 | \$ 24.34 | \$ 19.24 |
| Capital Expenditures | | | | | | |
| Exploration and development | \$ 41,864 | \$ 48,292 | \$ 90,156 | \$ 12,151 | \$ 55,878 | \$ 68,029 |
| Acquisitions, net of divestitures | \$ (3,937) | \$ — | \$ (3,937) | \$ (218) | \$ (104) | \$ (322) |

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

2018 GUIDANCE

We announced our 2018 capital budget of \$325 to \$375 million and production guidance of 68,000 to 72,000 boe/d in December 2017. The 2018 capital budget is approximately 60% weighted to the first half of the year and we have the operational flexibility to adjust our spending plans based on changes in the commodity price environment. This budget is weighted to drilling and completion activities (approximately 83%) with the balance for facilities (approximately 16%) and land and seismic (approximately 1%).

Based on the mid-point of our production guidance range of 70,000 boe/d, approximately 51% of our production is expected to be generated in the Eagle Ford with the remaining 49% from Canada. Our production mix is forecast to be 80% liquids (38% heavy oil, 30% light oil and condensate and 12% natural gas liquids) and 20% natural gas.

Our 2018 capital plans include approximately \$30 million of non-recurring infrastructure investment in Peace River and Lloydminster to support future development and growth. This includes costs related to our 50% working interest in a 18 mmcf/d natural gas plant and related pipeline infrastructure in Peace River as part of our gas conservation strategy. It also includes pipelines, compression and

road construction on our acquired Peace River lands where we expect to drill multi-lateral horizontal wells in the Seal region. We have also planned an expansion of our Kerrobert thermal facility to accommodate a steam-assisted gravity drainage program in 2018 and 2019.

2018 Guidance

| | |
|-------------------------------------|---|
| Exploration and development capital | \$325-\$375 million |
| Production | 68,000 to 72,000 boe/d |
| Expenses: | |
| Royalty rate | approximately 23% |
| Operating | \$10.50-\$11.25/boe |
| Transportation | \$1.35-\$1.45/boe |
| General and administrative | approximately \$44 million or \$1.72/boe |
| Interest | approximately \$100 million or \$3.95/boe |

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2017, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, NGL reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The estimation of reserves is a complex process requiring significant judgment. Estimates of the Company's reserves are reviewed annually by independent reserves evaluators and represent the estimated recoverable quantities of crude oil, natural gas and NGLs and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGLs and their future net cash flows are based on a number of variable factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

Cash Generating Units

The Company's capital oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash flows that are largely independent of the cash flows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when calculation of recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication

of impairment or impairment reversal. When completing this assessment, management considers internal and external sources of information including changes in future commodity prices, changes in industry regulations or royalty rates, asset performance and changes in the Company's estimates of economically recoverable reserves.

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including estimates of reserve quantities, the discount rates used to present value future cash flows, future commodity prices and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of recoverable amount and the carrying value of assets.

Exploration and Evaluation Assets ("E&E")

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with International Financial Reporting Standards ("IFRS"). The determination of fair value assigned to assets acquired and liabilities assumed often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and E&E assets acquired include estimates of reserves acquired, forecast benchmark commodity prices and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill.

Joint Arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, management considers whether the decisions regarding the capital and operating activities of the arrangement require unanimous consent.

Classification of a joint arrangement once joint control has been established also requires judgment. The type of joint arrangement is determined by assessing the rights and obligations arising from the arrangement given the structure, legal form, and terms agreed upon by the parties sharing control. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures. Arrangements where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, are classified as joint operations.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses estimates of future commodity prices available at period end to determine the fair value of outstanding financial derivatives. Changes in market pricing between period end and settlement of the derivative contracts could have a significant impact on financial results related to the financial derivatives.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are based on the Company's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Foreign Operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. The designation of a subsidiary's functional currency is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

Legal

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

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. Interpretation and application of existing regulation and legislation requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Revenue from Contracts with Customers

In April 2016, the International Accounting Standards Board ("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 can 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. The Company has substantially completed its review of the various revenue streams and underlying contracts with customers and does not anticipate a material impact to the Company's net income. The Company will expand the disclosures in the notes to the financial statements as prescribed by IFRS 15 to provide additional information on the Company's various revenue streams and contractual arrangements.

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. The Company will adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company has concluded that the standard will not have a material 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 developing a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2017, an evaluation was conducted of the effectiveness of our "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable

rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

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

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

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2017. The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, as reflected in their report for 2017.

Changes in Internal Control Over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial results. Listed below is a description of these risk and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2017 under the "Risk Factors" section.

Volatility of Oil and Natural Gas Prices

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

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

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

Decreases to or a prolonged period of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently

producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

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

Access to Capital Markets

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

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

Debt Service and Refinancing

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

Our existing Revolving Facilities and any replacement facilities may not provide sufficient liquidity. We currently have Revolving Facilities in the amount of US\$575 million. The amounts available under our existing Revolving Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our Revolving Facilities will be adequate for our future financial obligations, including our future capital expenditure program, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Revolving Facilities are not extended before June 2019, indebtedness under the Revolving Facilities will be repayable at that time. In addition, we are required to repay the long-term notes on maturity. There is a risk that the Revolving Facilities will not be renewed for the same amount or on the same terms.

Debt Covenant Compliance

We are required to comply with the covenants in our Revolving Facilities and long-term notes. If we fail to comply with our debt covenants, are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our secured creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our shareholders.

Non-operating Agreements in the U.S.

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

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

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such operation.

Access to Transportation Capacity

We deliver our products through gathering, processing and pipeline systems which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price for crude oil. Although pipeline expansions are ongoing, the lack of pipeline capacity continues to affect the oil and natural gas industry in Canada and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that investment in pipelines, which would result in additional long-term take-away capacity, will be made by applicable third party pipeline providers or that any requisite applications will receive regulatory approval. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may, from time to time, be processed through facilities controlled by third parties. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Public perception and influence on regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could impede our business or make our operations more expensive.

Environmental Regulation and Risk

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

Climate Change Regulation

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

The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at \$10/tonne and rising by \$10/tonne a year to \$50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the provinces and territories and would only be implemented in those provinces and territories that do not have their own carbon tax.

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

Variations in Interest Rates

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

Variations in Foreign Exchange Rates

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

Risk Management

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

Changes to Income tax and other laws

We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details see "*Income Taxes*".

Reserve Estimates

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

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

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

Credit Risk

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

Information Technology Risks

We utilize a number of information technology systems for the administration and management of our business. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although our information technology systems are considered to be secure, if an unauthorized party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.

Additional Business Risks

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

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; our expectation regarding the payment of cash income taxes prior to 2022; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the existence, operation and strategy of our risk management program; our capital budget for 2018; our annual average production rate for 2018; the portion of our 2018 capital budget to be spent in the first half of the year; the breakdown of our 2018 capital budget by expenditure type; the geographic breakdown of our 2018 production; our production mix for 2018; our plans for developing our properties; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2018; the impact of the adoption of new accounting standards on our financial results; and that we are in material compliance with current applicable environmental legislation. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices; 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, 2017, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2017, our internal control over financial reporting was effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2017.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

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



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



Rodney D. Gray
Chief Financial Officer
Baytex Energy Corp.

March 5, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Baytex Energy Corp. (the “Company”), which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the “consolidated financial statements”).

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on Internal Control Over Financial Reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 5, 2018 expressed an unqualified (unmodified) opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

A - Management’s Responsibility for the Consolidated Financial Statements

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

B - Auditors’ Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditors since 2016.

March 5, 2018
Calgary, Canada

INDEPENDENT AUDITORS' REPORT

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

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (the "Company") internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Report on the Consolidated Financial Statements

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company, which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 5, 2018 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB and in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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



Chartered Professional Accountants
March 5, 2018
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(thousands of Canadian dollars)

| As at | December 31, 2017 | December 31, 2016 |
|--|-------------------|-------------------|
| ASSETS | | |
| Current assets | | |
| Cash | \$ — | \$ 2,705 |
| Trade and other receivables (note 18) | 112,844 | 112,171 |
| Financial derivatives (note 18) | 18,510 | 2,219 |
| | 131,354 | 117,095 |
| Non-current assets | | |
| Exploration and evaluation assets (note 6) | 272,974 | 308,462 |
| Oil and gas properties (note 7) | 3,958,309 | 4,152,169 |
| Other plant and equipment (note 8) | 9,474 | 16,359 |
| | \$ 4,372,111 | \$ 4,594,085 |
| LIABILITIES | | |
| Current liabilities | | |
| Trade and other payables (note 18) | \$ 144,542 | \$ 112,973 |
| Financial derivatives (note 18) | 50,095 | 28,532 |
| Onerous contracts (note 19) | 2,574 | 9,504 |
| | 197,211 | 151,009 |
| Non-current liabilities | | |
| Bank loan (note 9) | 212,138 | 187,954 |
| Long-term notes (note 10) | 1,474,184 | 1,566,116 |
| Asset retirement obligations (note 11) | 368,995 | 331,517 |
| Deferred income tax liability (note 15) | 204,698 | 375,695 |
| Financial derivatives (note 18) | — | 2,833 |
| | 2,457,226 | 2,615,124 |
| SHAREHOLDERS' EQUITY | | |
| Shareholders' capital (note 12) | 4,443,576 | 4,422,661 |
| Contributed surplus | 15,999 | 21,405 |
| Accumulated other comprehensive income | 463,104 | 629,863 |
| Deficit | (3,007,794) | (3,094,968) |
| | 1,914,885 | 1,978,961 |
| | \$ 4,372,111 | \$ 4,594,085 |

Commitments and contingencies (note 20)

See accompanying notes to the consolidated financial statements.



Naveen Dargan
Director, Baytex Energy Corp.



Gregory K. Melchin
Director, Baytex Energy Corp.

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

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

| Years Ended December 31 | 2017 | 2016 |
|--|--------------------|---------------------|
| Revenue, net of royalties | | |
| Petroleum and natural gas sales | \$ 1,091,534 | \$ 780,095 |
| Royalties | (241,892) | (178,116) |
| | 849,642 | 601,979 |
| Expenses | | |
| Operating | 269,283 | 240,705 |
| Transportation | 33,985 | 28,257 |
| Blending | 51,012 | 9,622 |
| General and administrative | 47,389 | 50,866 |
| Exploration and evaluation (note 6) | 8,253 | 5,976 |
| Depletion and depreciation (notes 7 and 8) | 481,929 | 508,309 |
| Impairment (notes 6 and 7) | — | 423,176 |
| Share-based compensation (note 13) | 15,509 | 13,882 |
| Financing and interest (note 16) | 113,638 | 114,199 |
| Financial derivatives (gain) loss (note 18) | (5,177) | 43,207 |
| Foreign exchange gain (note 17) | (87,060) | (42,678) |
| Gain on disposition of oil and gas properties (note 7) | (12,081) | (43,907) |
| Other | 2,216 | 8,152 |
| | 918,896 | 1,359,766 |
| Net loss before income taxes | (69,254) | (757,787) |
| Income tax recovery (note 15) | | |
| Current income tax recovery | (1,085) | (8,042) |
| Deferred income tax recovery | (155,343) | (264,561) |
| | (156,428) | (272,603) |
| Net income (loss) attributable to shareholders | \$ 87,174 | \$ (485,184) |
| Other comprehensive loss | | |
| Foreign currency translation adjustment | (166,759) | (75,519) |
| Comprehensive loss | \$ (79,585) | \$ (560,703) |
| Net income (loss) per common share (note 14) | | |
| Basic | \$ 0.37 | \$ (2.29) |
| Diluted | \$ 0.37 | \$ (2.29) |
| Weighted average common shares (note 14) | | |
| Basic | 234,787 | 212,298 |
| Diluted | 237,249 | 212,298 |

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars)

| | Shareholders' capital | Contributed surplus | Accumulated other comprehensive income | 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 (note 12) | 14,522 | (14,522) | — | — | — |
| Share-based compensation (note 13) | — | 13,882 | — | — | 13,882 |
| Issued for cash (note 12) | 115,014 | — | — | — | 115,014 |
| Issuance costs, net of tax (note 12) | (3,706) | — | — | — | (3,706) |
| Comprehensive loss for the year | — | — | (75,519) | (485,184) | (560,703) |
| Balance at December 31, 2016 | \$ 4,422,661 | \$ 21,405 | \$ 629,863 | \$ (3,094,968) | \$ 1,978,961 |
| Vesting of share awards (note 12) | 20,915 | (20,915) | — | — | — |
| Share-based compensation (note 13) | — | 15,509 | — | — | 15,509 |
| Comprehensive loss for the year | — | — | (166,759) | 87,174 | (79,585) |
| Balance at December 31, 2017 | \$ 4,443,576 | \$ 15,999 | \$ 463,104 | \$ (3,007,794) | \$ 1,914,885 |

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars)

| Years Ended December 31 | 2017 | 2016 |
|--|------------------|------------------|
| CASH PROVIDED BY (USED IN): | | |
| Operating activities | | |
| Net income (loss) for the year | \$ 87,174 | \$ (485,184) |
| Adjustments for: | | |
| Share-based compensation (note 13) | 15,509 | 13,882 |
| Unrealized foreign exchange gain (note 17) | (86,649) | (41,436) |
| Exploration and evaluation (note 6) | 8,253 | 5,976 |
| Depletion and depreciation (notes 7 and 8) | 481,929 | 508,309 |
| Impairment (notes 6 and 7) | — | 423,176 |
| Non-cash financing and accretion (note 16) | 13,156 | 10,514 |
| Loss on onerous contracts (note 19) | — | 10,116 |
| Unrealized financial derivatives loss (note 18) | 2,439 | 140,136 |
| Gain on disposition of oil and gas properties (note 7) | (12,081) | (43,907) |
| Deferred income tax recovery | (155,343) | (264,561) |
| Payments on onerous contracts (note 19) | (6,746) | (770) |
| Asset retirement obligations settled (note 11) | (13,471) | (5,616) |
| Change in non-cash working capital (note 19) | (8,962) | (23,270) |
| | 325,208 | 247,365 |
| Financing activities | | |
| Increase (decrease) in bank loan | 33,347 | (62,569) |
| Redemption of long-term notes (note 10) | (8,582) | — |
| Issuance of common shares, net of issuance costs (note 12) | — | 109,939 |
| | 24,765 | 47,370 |
| Investing activities | | |
| Additions to exploration and evaluation assets (note 6) | (7,118) | (4,716) |
| Additions to oil and gas properties (note 7) | (319,148) | (220,067) |
| Additions to other plant and equipment, net of dispositions | (238) | 5,129 |
| Property acquisitions (notes 4 and 7) | (71,643) | (117) |
| Proceeds from disposition of oil and gas properties (note 7) | 11,786 | 63,237 |
| Change in non-cash working capital (note 19) | 33,683 | (135,743) |
| | (352,678) | (292,277) |
| Change in cash | (2,705) | 2,458 |
| Cash, beginning of year | 2,705 | 247 |
| Cash, end of year | \$ — | \$ 2,705 |
| Supplementary information | | |
| Interest paid | \$ 105,513 | \$ 104,183 |
| Income taxes paid | \$ 49 | \$ 5,332 |

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2017 and 2016

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

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

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

The consolidated financial statements were approved by the Board of Directors of Baytex on March 5, 2018.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGLs") reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The estimation of reserves is a complex process requiring significant judgment. Estimates of the Company's reserves are reviewed annually by independent reserves evaluators and represent the estimated recoverable quantities of crude oil, natural gas and NGLs and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGLs and their future net cash flows are based on a number of variable factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

Cash-generating Units ("CGUs")

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash flows that are largely independent of the cash flows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when calculation of recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. When completing this assessment, management considers internal and external sources of information including changes in future commodity prices, changes in industry regulations or royalty rates, asset performance and changes in the Company's estimates of economically recoverable reserves.

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including estimates of reserve quantities, the discount rates used to present value future cash flows, future commodity prices and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of recoverable amount and the carrying value of assets.

Exploration and Evaluation ("E&E") Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of fair value assigned to assets acquired and liabilities assumed often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and E&E assets acquired include estimates of reserves acquired, forecast benchmark commodity prices and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill.

Joint Arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, management considers whether the decisions regarding the capital and operating activities of the arrangement require unanimous consent.

Classification of a joint arrangement once joint control has been established also requires judgment. The type of joint arrangement is determined by assessing the rights and obligations arising from the arrangement given the structure, legal form, and terms agreed upon by the parties sharing control. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures. Arrangements where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, are classified as joint operations.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses estimates of future commodity prices available at period end to determine the fair value of outstanding financial derivatives. Changes in market pricing between period end and settlement of the derivative contracts could have a significant impact on financial results related to the financial derivatives.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations are based on the Company's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Foreign Operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. The designation of a subsidiary's functional currency is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

Legal

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

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. Interpretation and application of existing regulation and legislation requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Partnership. Intercompany balances and transactions are eliminated in preparation of the consolidated financial statements.

Many of the Company's exploration, development and production activities are conducted through jointly controlled operations. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by jointly controlled operations.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the acquired assets meet the definition of a business under IFRS. The cost of an acquisition is measured as cash paid and the fair value of assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss. Associated transaction costs are expensed when incurred.

Exploration and Evaluation Assets

Pre-license costs, including certain geological, geophysical and seismic expenditures, are incurred before the legal rights to explore a specific area have been obtained. These costs are charged to exploration expense in the period in which they are incurred.

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as an intangible asset until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract the underlying reserves. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E costs associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by the classification of proved or probable reserves and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Items of oil and gas properties are initially recorded at cost. The initial cost of oil and gas properties includes the costs to acquire developed or producing oil and gas properties, and to develop oil and gas properties, such as costs of completing geological and geophysical surveys, drilling development wells, and the costs to construct and install development infrastructure such as wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the future economic benefits of the replacement will be realized by the Company. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Borrowing costs that are directly attributable to an item of oil and gas properties that takes a substantial period of time to construct are capitalized as part of the asset. Capitalization of borrowing costs ceases when the asset is in the condition and location necessary for its intended use.

Depletion and Depreciation

The costs associated with an item of oil and gas properties are depleted on a unit-of-production basis over proved plus probable reserves once commercial production has commenced. Future development costs required to bring those reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

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

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

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

Impairment

Non-derivative financial assets

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

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. Impairment losses are recognized in net income or loss. An impairment loss is reversed when there is objective evidence that the value of the financial assets has been partially or fully restored. For financial assets measured at amortized cost the reversal is recognized in net income or loss.

Non-financial assets

The Company reviews its non-financial assets, other than E&E assets, for indicators of impairment and impairment reversal at the end of each reporting period. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist. E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

When reviewing for indicators of impairment and impairment reversal, and testing for impairment when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. FVLCD is determined as the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction between

willing parties. In determining FVLCD, recent market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a pre-tax discount rate that reflects current market assessments of the time value of money.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset's revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized. Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the risk free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within finance expense in the statements of income or loss. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign transactions

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

Foreign operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. The designation of a subsidiary's functional currency is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

The financial statements of each entity are translated into Canadian dollars in preparation of the Company's consolidated financial statements. The assets and liabilities of a foreign operation are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are recognized in other comprehensive income or loss.

If the Company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net income or loss.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the delivery point and collection is reasonably assured. Revenue from the sale of petroleum and natural gas in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant agreements. Purchases

and sales of product that are entered into in contemplation of each other with the same counterparty with the right and intent to settle net are recorded on a net basis.

Transportation Expense

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

Financial Instruments

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

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

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

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

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

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

Income Taxes

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

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

The Company follows the balance sheet asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary

differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

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

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Under the Share Award Incentive Plan, common shares are issued as to one-sixth every six months from the date of issuance. Expenses related to the Share Award Incentive Plan are determined based on the fair value of the share awards on the grant date which is based on quoted market prices for the Company's common shares. Both restricted and performance awards are expensed over the vesting period using the graded vesting method. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

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 can 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. The Company has substantially completed its review of the various revenue streams and underlying contracts with customers and does not anticipate a material impact to the Company's net income. The Company will expand the disclosures in the notes to the financial statements as prescribed by IFRS 15 to provide additional information on the Company's various revenue streams and contractual arrangements.

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 or loss rather than net income or 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. The Company will adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company has concluded that the standard will not have a material 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 or 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. The Company will adopt IFRS 16 on January 1, 2019. The Company is developing a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have 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 fair value of the oil and gas properties acquired was determined using a third-party evaluation of proved plus probable reserves with an effective date of December 31, 2017, utilizing forward prices at the date of acquisition and adjustment for the results of operations between the acquisition date and December 31, 2017. 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%.

Final 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 |
| Purchase price equation: | | |
| 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, as at the acquisition date.

For the period from January 20, 2017 to December 31, 2017, the acquired properties contributed revenues, net of royalties, of \$61.0 million and operating income (revenues, net of royalties, less operating, transportation and blending expenses) of \$10.8 million.

5. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- 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.

| Years Ended December 31 | Canada | | U.S. | | Corporate | | Consolidated | |
|---|--------------------|---------------------|-------------------|--------------------|--------------------|---------------------|-------------------|---------------------|
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| Revenue, net of royalties | | | | | | | | |
| Petroleum and natural gas sales | \$ 470,239 | \$ 299,632 | \$ 621,295 | \$ 480,463 | \$ — | \$ — | \$ 1,091,534 | \$ 780,095 |
| Royalties | (58,672) | (37,720) | (183,220) | (140,396) | — | — | (241,892) | (178,116) |
| | 411,567 | 261,912 | 438,075 | 340,067 | — | — | 849,642 | 601,979 |
| Expenses | | | | | | | | |
| Operating | 181,995 | 142,242 | 87,288 | 98,463 | — | — | 269,283 | 240,705 |
| Transportation | 33,985 | 28,257 | — | — | — | — | 33,985 | 28,257 |
| Blending | 51,012 | 9,622 | — | — | — | — | 51,012 | 9,622 |
| General and administrative | — | — | — | — | 47,389 | 50,866 | 47,389 | 50,866 |
| Exploration and evaluation | 8,253 | 5,976 | — | — | — | — | 8,253 | 5,976 |
| Depletion and depreciation | 199,149 | 210,778 | 280,933 | 293,231 | 1,847 | 4,299 | 481,929 | 508,309 |
| Impairment | — | 256,559 | — | 166,617 | — | — | — | 423,176 |
| Share-based compensation | — | — | — | — | 15,509 | 13,882 | 15,509 | 13,882 |
| Financing and interest | — | — | — | — | 113,638 | 114,199 | 113,638 | 114,199 |
| Financial derivatives (gain) loss | — | — | — | — | (5,177) | 43,207 | (5,177) | 43,207 |
| Foreign exchange gain | — | — | — | — | (87,060) | (42,678) | (87,060) | (42,678) |
| Gain on disposition of oil and gas properties | (12,048) | (3,883) | (33) | (40,024) | — | — | (12,081) | (43,907) |
| Other | — | — | — | — | 2,216 | 8,152 | 2,216 | 8,152 |
| | 462,346 | 649,551 | 368,188 | 518,287 | 88,362 | 191,927 | 918,896 | 1,359,766 |
| Net income (loss) before income taxes | (50,779) | (387,639) | 69,887 | (178,220) | (88,362) | (191,927) | (69,254) | (757,787) |
| Income tax recovery | | | | | | | | |
| Current income tax recovery | — | (6,577) | (1,085) | (1,156) | — | (309) | (1,085) | (8,042) |
| Deferred income tax expense (recovery) | 622 | (99,215) | (118,163) | (112,907) | (37,802) | (52,439) | (155,343) | (264,561) |
| | 622 | (105,792) | (119,248) | (114,063) | (37,802) | (52,748) | (156,428) | (272,603) |
| Net income (loss) | \$ (51,401) | \$ (281,847) | \$ 189,135 | \$ (64,157) | \$ (50,560) | \$ (139,179) | \$ 87,174 | \$ (485,184) |
| Total oil and natural gas capital expenditures⁽¹⁾ | | | | | | | | |
| | \$ 173,131 | \$ 16,990 | \$ 212,992 | \$ 144,673 | \$ — | \$ — | \$ 386,123 | \$ 161,663 |

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

| As at | December 31, 2017 | December 31, 2016 |
|----------------------------------|---------------------|---------------------|
| Canadian assets | \$ 1,677,821 | \$ 1,625,546 |
| U.S. assets | 2,684,816 | 2,955,965 |
| Corporate assets | 9,474 | 12,574 |
| Total consolidated assets | \$ 4,372,111 | \$ 4,594,085 |

6. EXPLORATION AND EVALUATION ASSETS

| | December 31, 2017 | December 31, 2016 |
|------------------------------------|-------------------|-------------------|
| Balance, beginning of year | \$ 308,462 | \$ 578,969 |
| Capital expenditures | 7,118 | 4,716 |
| Divestitures | (1,276) | (2,353) |
| Impairment | — | (166,617) |
| Exploration and evaluation expense | (8,253) | (5,976) |
| Transfer to oil and gas properties | (20,198) | (85,069) |
| Foreign currency translation | (12,879) | (15,208) |
| Balance, end of year | \$ 272,974 | \$ 308,462 |

At December 31, 2017, there were no indicators of impairment for exploration and evaluation assets on any of the Company's CGUs. During the year ended December 31, 2017, the Company transferred \$20.2 million from exploration and evaluation to oil and gas properties upon establishment of developed reserves in the U.S. CGU that were previously classified as undeveloped reserves.

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

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 | 319,148 | — | 319,148 |
| Property acquisitions ⁽¹⁾ | 136,007 | — | 136,007 |
| Transferred from exploration and evaluation assets | 20,198 | — | 20,198 |
| Transferred from other assets | 5,124 | — | 5,124 |
| Change in asset retirement obligations | 42,808 | — | 42,808 |
| Divestitures | (105,272) | 49,291 | (55,981) |
| Foreign currency translation | (249,723) | 68,641 | (181,082) |
| Depletion | — | (480,082) | (480,082) |
| Balance, December 31, 2017 | \$ 7,932,327 | \$ (3,974,018) | \$ 3,958,309 |

(1) Includes \$53.5 million related to the acquisition of heavy oil properties completed during the year ended December 31, 2017, in addition to amounts related to the property acquisition disclosed in note 4.

During the fourth quarter of 2017, the Company closed an arrangement to swap its working interest in certain oil and gas properties in exchange for non-monetary proceeds of \$40.0 million. The fair value of non-monetary proceeds, including producing oil and gas properties geographically located in the Company's Lloydminster CGU, was determined based on the proved plus probable reserves evaluated as at December 31, 2017 by an independent reserve engineer. The Company recorded a gain of \$19.3 million on the swap as a result of the fair value of acquired assets exceeding the carrying value of the disposed assets. The disposed assets included \$26.5 million of oil and gas properties and \$8.0 million of asset retirement obligations.

At the end of each reporting period, the Company performs an assessment to determine whether there is any indication of impairment or reversal of previously recorded impairments for the CGUs that comprise oil and gas properties. The assessment of indicators is subjective in nature and requires Management to make judgments based on the information available at the reporting date. The Company determined that there were no indicators of impairment or impairment reversals for any of the Company's CGUs as at December 31, 2017.

In 2016, the Company recorded a \$26.6 million impairment expense in its Lloydminster CGU on assets that were reclassified from oil and gas assets to assets held for sale prior to their disposition in the fourth quarter of 2016. The carrying value of the assets transferred to assets held for sale exceeded the fair value (being the sales price) resulting in the impairment.

At December 31, 2016, indicators of impairment existed for the Peace River CGU as a result of downward technical revisions to reserves. Impairment of \$230.0 million was recorded in the Peace River CGU. The recoverable amount for the Peace River CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2016. The recoverable amount of oil and gas properties of \$550.2 million for the Peace River CGU was estimated based on their fair value less costs of disposal at December 31, 2016. For impairment assessments of oil and gas properties, the Company estimates the recoverable amount using a discounted cash flow model based on an independent reserve report approved by the Board of Directors on an annual basis and a range of pre-tax discount rates of 10% to 15%. The total impairment expense recorded to oil and gas properties by the Company in 2016 was \$256.6 million.

The recoverable amount of the Peace River CGU is classified as a Level 3 fair value measurement and was calculated at December 31, 2016 using the following benchmark reference prices for the years 2017 to 2021 adjusted for commodity differentials specific to the Company:

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

8. OTHER PLANT AND EQUIPMENT

| | Cost | Accumulated depreciation | Net book value |
|---------------------------------------|------------------|--------------------------|-----------------|
| Balance, December 31, 2015 | \$ 72,878 | \$ (46,854) | \$ 26,024 |
| Capital expenditures | 1,934 | — | 1,934 |
| Dispositions, net of acquisitions | (7,063) | — | (7,063) |
| Foreign currency translation | (51) | 46 | (5) |
| Depreciation | — | (4,531) | (4,531) |
| Balance, December 31, 2016 | 67,698 | (51,339) | 16,359 |
| Capital expenditures | 329 | — | 329 |
| Dispositions, net of acquisitions | (255) | — | (255) |
| Transferred to oil and gas properties | (5,124) | — | (5,124) |
| Foreign currency translation | — | 12 | 12 |
| Depreciation | — | (1,847) | (1,847) |
| Balance, December 31, 2017 | \$ 62,648 | \$ (53,174) | \$ 9,474 |

9. BANK LOAN

| | December 31, 2017 | December 31, 2016 |
|--|-------------------|-------------------|
| Bank loan - U.S. dollar denominated ⁽¹⁾ | \$ 167,159 | \$ 191,286 |
| Bank loan - Canadian dollar denominated | 46,217 | — |
| Bank loan - principal | 213,376 | 191,286 |
| Unamortized debt issuance costs | (1,238) | (3,332) |
| Bank loan | \$ 212,138 | \$ 187,954 |

(1) U.S. dollar denominated bank loan balance as at December 31, 2017 was US\$133.5 million (US\$142.5 million as at December 31, 2016).

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

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

At December 31, 2017, Baytex had \$14.6 million of outstanding letters of credit (December 31, 2016 - \$12.6 million) under the Revolving Facilities.

At December 31, 2017, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants contained in the Revolving Facilities and Baytex's compliance therewith as at December 31, 2017.

| Covenant Description | Ratio for the Quarter(s) ending: | | | | |
|--|----------------------------------|-------------------------------------|-------------------------------------|-------------------|------------|
| | Position as at December 31, 2017 | December 31, 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) | 0.50:1.00 | 5.00:1.00 | 4.50:1.00 | 4.00:1.00 | 3.50:1.00 |
| Interest Coverage ⁽³⁾ (Minimum Ratio) | 4.54:1.00 | 1.25:1.00 | 1.50:1.00 | 1.75:1.00 | 2.00:1.00 |

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2017, the Company's Senior Secured Debt totaled \$228 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2017 was \$454 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2017 were \$100 million.

10. LONG-TERM NOTES

| | December 31, 2017 | December 31, 2016 |
|--|-------------------|-------------------|
| 7.5% notes (US\$6,400 – principal) redeemed July 13, 2017 | \$ — | \$ 8,593 |
| 6.75% notes (US\$150,000 – principal) due February 17, 2021 | 187,770 | 201,405 |
| 5.125% notes (US\$400,000 – principal) due June 1, 2021 | 500,720 | 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 | 500,720 | 537,080 |
| Total long-term notes - principal | 1,489,210 | 1,584,158 |
| Unamortized debt issuance costs | (15,026) | (18,042) |
| Total long-term notes - net of unamortized debt issuance costs | \$ 1,474,184 | \$ 1,566,116 |

On July 13, 2017, the Company redeemed the remaining US\$6.4 million principal amount of 7.5% senior unsecured notes assumed pursuant to the acquisition of Aurora Oil and Gas Limited on June 11, 2014.

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Revolving Facilities and long-term notes unless the Company maintains a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 9) to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2017, the fixed charge coverage ratio was 4.54:1.00.

11. ASSET RETIREMENT OBLIGATIONS

| | December 31, 2017 | December 31, 2016 |
|--|-------------------|-------------------|
| Balance, beginning of year | \$ 331,517 | \$ 296,002 |
| Liabilities incurred | 5,825 | 5,642 |
| Liabilities settled | (13,471) | (5,616) |
| Liabilities acquired ⁽¹⁾ | 22,264 | — |
| Liabilities divested | (19,940) | (10,590) |
| Accretion | 8,682 | 6,174 |
| Change in estimate ⁽²⁾ | (24,028) | 20,402 |
| Changes in discount rates and inflation rates ⁽³⁾ | 61,011 | 20,260 |
| Foreign currency translation | (2,865) | (757) |
| Balance, end of year | \$ 368,995 | \$ 331,517 |

(1) Includes \$3.2 million related to the acquisition of other heavy oil properties during the year ended December 31, 2017, in addition to amounts related to the property acquisition disclosed in note 4.

(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 change in discount rate includes \$64.0 million related to the Peace River property acquisition (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.

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years.

The undiscounted amount of estimated cash flow required to settle the asset retirement obligations is \$420.3 million (December 31, 2016 - \$365.1 million). Based on an inflation rate of 2.00% (December 31, 2016 - 1.75%), the undiscounted amount of estimated future cash flows required to settle the obligation is \$756.7 million (December 31, 2016 - 605.4 million).

The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2017 using an estimated annual inflation rate of 2.00% (December 31, 2016 - 1.75%) and discounted at a risk free rate of 2.50% (December 31, 2016 - 2.25%) is \$369.0 million (December 31, 2016 - \$331.5 million).

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 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 | 2,002 | 20,915 |
| Balance, December 31, 2017 | 235,451 | \$ 4,443,576 |

On December 12, 2016, Baytex issued 21.9 million common shares for aggregate gross proceeds of approximately \$115.0 million (\$109.9 million net of issue costs). Issuance costs of \$5.1 million (\$3.7 million after tax) were recorded as a reduction to shareholders' capital.

13. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of \$15.5 million for the year ended December 31, 2017 (\$13.9 million for the year ended December 31, 2016).

The weighted average fair value of share awards granted during the year ended December 31, 2017 was \$5.75 per restricted and performance award and \$3.04 per restricted and performance award for the year ended December 31, 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 | 1,636 | 1,584 | 3,220 |
| Vested and converted to common shares | (959) | (1,043) | (2,002) |
| Forfeited | (157) | (25) | (182) |
| Balance, December 31, 2017 | 2,028 | 2,253 | 4,281 |

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

14. NET INCOME (LOSS) PER SHARE

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

| | Years Ended December 31 | | | | | |
|---------------------------------|-------------------------|---|-------------------------|--------------|---|-----------------------|
| | 2017 | | | 2016 | | |
| | Net income | Weighted average common shares (000s) | Net income per share | Net loss | Weighted average common shares (000s) | Net loss per share |
| Net income (loss) - basic | \$ 87,174 | 234,787 | \$ 0.37 | \$ (485,184) | 212,298 | \$ (2.29) |
| Dilutive effect of share awards | — | 2,462 | — | — | — | — |
| Net income (loss) - diluted | \$ 87,174 | 237,249 | \$ 0.37 | \$ (485,184) | 212,298 | \$ (2.29) |

For the years ended December 31, 2017 and 2016, the effect of no share awards and 3.2 million share awards, respectively, were excluded from the calculation of dilutive earnings per share as they were determined to be anti-dilutive.

15. INCOME TAXES

The provision for income taxes has been computed as follows:

| | Years Ended December 31 | |
|--|-------------------------|--------------|
| | 2017 | 2016 |
| Net loss before income taxes | \$ (69,254) | \$ (757,787) |
| Expected income taxes at the statutory rate of 26.93% (2016 – 27.00%) ⁽¹⁾ | (18,650) | (204,602) |
| Increase (decrease) in income tax recovery resulting from: | | |
| Share-based compensation | 4,177 | 3,610 |
| Non-taxable portion of foreign exchange (gain) loss | (11,615) | (5,309) |
| Effect of change in income tax rates ⁽¹⁾ | (104) | 1,180 |
| Effect of rate adjustments for foreign jurisdictions | (42,214) | (63,745) |
| Effect of U.S. tax reform ⁽²⁾ | (91,830) | — |
| Effect of change in deferred tax benefit not recognized ⁽³⁾ | (11,615) | (5,309) |
| Adjustments and assessments ⁽⁴⁾ | 15,423 | 1,572 |
| Income tax recovery | \$ (156,428) | \$ (272,603) |

(1) Expected income tax rate decreased due to a decrease in the corporate income tax rate in Saskatchewan (from 12% to 11.75%).

(2) On December 22, 2017, the United States of America (the "U.S.") enacted the Tax Cuts and Jobs Act which altered the federal income tax law that applies to Baytex's U.S. subsidiary. The changes include a reduction of the statutory income tax rate to 21% from 35%, resulting in a \$91.8 million deferred tax recovery.

(3) A deferred income tax asset has not been recognized for allowable capital losses of \$86 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes (\$129 million as at December 31, 2016).

(4) The Company is regularly subject to audit by the revenue authorities in the jurisdictions in which it operates. During the year ended December 31, 2017, the Company accepted an audit proposal from the Canada Revenue Agency which reduced certain non-capital loss tax pools by \$39.3 million and resulted in a \$10.6 million increase in deferred tax expense.

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

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

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

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

| As at | January 1, 2017 | Recognized in Net Loss | Share Issuance Costs | Foreign Currency Translation Adjustment | December 31, 2017 |
|--|--------------------|---------------------------|----------------------------|--|----------------------|
| Taxable temporary differences: | | | | | |
| Petroleum and natural gas properties | \$ (967,579) | \$ 221,697 | \$ — | \$ 49,455 | \$ (696,427) |
| Financial derivatives | 7,869 | 659 | — | — | 8,528 |
| Deferred income | (419) | (17,408) | — | — | (17,827) |
| Other | (5,018) | 6,076 | — | (7,014) | (5,956) |
| Deductible temporary differences: | | | | | |
| Asset retirement obligations | 93,016 | 5,925 | — | (964) | 97,977 |
| Financial derivatives | — | — | — | — | — |
| Non-capital losses | 404,952 | (48,380) | — | (25,823) | 330,749 |
| Finance costs | 91,484 | (13,226) | — | — | 78,258 |
| Net deferred income tax liability ⁽¹⁾ | \$ (375,695) | \$ 155,343 | \$ — | \$ 15,654 | \$ (204,698) |

(1) Non-capital loss carry-forwards at December 31, 2017 totaled \$1,478.5 million and expire from 2023 to 2037.

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

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

The following is a summary of Baytex's tax pools:

| | December 31, 2017 | December 31, 2016 |
|--|---------------------|---------------------|
| Canadian Tax Pools | | |
| Canadian oil and natural gas property expenditures | \$ 308,366 | \$ 198,525 |
| Canadian development expenditures | 176,188 | 250,239 |
| Canadian exploration expenditures | 1,343 | 210 |
| Undepreciated capital costs | 228,739 | 256,549 |
| Non-capital losses | 337,808 | 151,959 |
| Financing costs and other | 46,986 | 69,025 |
| Total Canadian tax pools | \$ 1,099,430 | \$ 926,507 |
| U.S. Tax Pools | | |
| Depletion | \$ 183,406 | \$ 297,252 |
| Intangible drilling costs | 204,857 | 388,727 |
| Tangibles | 108,631 | 136,969 |
| Non-capital losses | 1,140,673 | 1,039,782 |
| Other | 303,357 | 201,896 |
| Total U.S. tax pools | \$ 1,940,924 | \$ 2,064,626 |

16. FINANCING AND INTEREST

| | Years Ended December 31 | |
|---|-------------------------|-------------------|
| | 2017 | 2016 |
| Interest on bank loan | \$ 11,439 | \$ 12,860 |
| Interest on long-term notes | 89,043 | 90,825 |
| Non-cash financing | 4,474 | 4,340 |
| Accretion on asset retirement obligations (note 11) | 8,682 | 6,174 |
| Financing and interest | \$ 113,638 | \$ 114,199 |

17. FOREIGN EXCHANGE

| | Years Ended December 31 | |
|----------------------------------|-------------------------|--------------------|
| | 2017 | 2016 |
| Unrealized foreign exchange gain | \$ (86,649) | \$ (41,436) |
| Realized foreign exchange gain | (411) | (1,242) |
| Foreign exchange gain | \$ (87,060) | \$ (42,678) |

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. Baytex aims to maximize the use of observable inputs, where practical. The fair values of financial instruments, other than financial derivatives, bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of financial derivatives are based on mark-to-market values of the underlying financial derivative contracts. The fair value of the bank loan is based on the principal amount of borrowings outstanding. The fair value of the long-term notes are based on the trading value of the notes.

Fair Value of Financial Instruments

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

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

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

| | December 31, 2017 | | December 31, 2016 | | Fair Value Measurement Hierarchy |
|------------------------------------|-------------------|----------------|-------------------|----------------|----------------------------------|
| | Carrying value | Fair value | Carrying value | Fair value | |
| Financial Assets | | | | | |
| <i>FVTPL⁽¹⁾</i> | | | | | |
| Cash | \$ — | \$ — | \$ 2,705 | \$ 2,705 | Level 1 |
| Derivatives | 18,510 | 18,510 | 2,219 | 2,219 | Level 2 |
| Total | \$ 18,510 | \$ 18,510 | \$ 4,924 | \$ 4,924 | |
| <i>Loans and receivables</i> | | | | | |
| Trade and other receivables | \$ 112,844 | \$ 112,844 | \$ 112,171 | \$ 112,171 | — |
| Total | \$ 112,844 | \$ 112,844 | \$ 112,171 | \$ 112,171 | |
| Financial Liabilities | | | | | |
| <i>FVTPL⁽¹⁾</i> | | | | | |
| Derivatives | \$ (50,095) | \$ (50,095) | \$ (31,365) | \$ (31,365) | Level 2 |
| Total | \$ (50,095) | \$ (50,095) | \$ (31,365) | \$ (31,365) | |
| <i>Other financial liabilities</i> | | | | | |
| Trade and other payables | \$ (144,542) | \$ (144,542) | \$ (112,973) | \$ (112,973) | — |
| Bank loan | (212,138) | (213,376) | (187,954) | (191,286) | — |
| Long-term notes | (1,474,184) | (1,430,902) | (1,566,116) | (1,435,165) | Level 1 |
| Total | \$ (1,830,864) | \$ (1,788,820) | \$ (1,867,043) | \$ (1,739,424) | |

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

There were no transfers between Level 1 and Level 2 in either 2017 or 2016.

Financial Risk

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

Market Risk

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

Foreign Currency Risk

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

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian to U.S. dollar exchange rate. At December 31, 2017 and 2016, the Company did not have any currency derivative contracts outstanding.

A \$0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income or loss before income taxes by approximately \$12.4 million.

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

| | Assets | | Liabilities | |
|-------------------------|-------------------|-------------------|----------------------|-------------------|
| | December 31, 2017 | December 31, 2016 | December 31, 2017 | December 31, 2016 |
| U.S. dollar denominated | US\$51,665 | US\$66,950 | US\$1,294,615 | US\$1,197,732 |

Interest Rate Risk

The Company's interest rate risk arises from the floating rate Revolving Facilities (note 9). As at December 31, 2017, the \$213.4 million principal amount of the Company's bank loan is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income or loss before income taxes for the year ended December 31, 2017 by approximately \$2.1 million.

Commodity Price Risk

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

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2017, a \$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately \$11.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2017, a \$0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately \$1.6 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of March 5, 2018:

| | Period | Volume | Price/Unit ⁽¹⁾ | Index | Fair Value ⁽²⁾ (\$ millions) |
|--------------------------------|----------------------|----------------|-------------------------------|----------|--|
| Oil | | | | | |
| Basis swap | Jan 2018 to Jun 2018 | 2,000 bbl/d | WTI less US\$14.23/bbl | WCS \$ | 3.1 |
| Basis swap | Jan 2018 to Dec 2018 | 6,000 bbl/d | WTI less US\$14.24/bbl | WCS \$ | 15.0 |
| Fixed - Sell | Jan 2018 to Dec 2018 | 13,000 bbl/d | US\$51.64/bbl | WTI \$ | (45.0) |
| 3-way option ⁽³⁾ | Jan 2018 to Dec 2018 | 2,000 bbl/d | US\$60.00/US\$54.40/US\$40.00 | WTI \$ | (1.2) |
| Fixed - Sell | Jan 2018 to Dec 2018 | 4,000 bbl/d | US\$61.31/bbl | Brent \$ | (6.5) |
| Fixed - Sell ⁽⁴⁾ | Feb 2018 to Dec 2018 | 1,000 bbl/d | US\$61.04/bbl | WTI \$ | — |
| Swaption ⁽⁴⁾⁽⁵⁾ | Jan 2019 to Dec 2019 | 2,000 bbl/d | US\$59.60/bbl | WTI \$ | — |
| 3-way option ⁽³⁾⁽⁴⁾ | Jan 2019 to Dec 2019 | 2,000 bbl/d | US\$70.00/US\$60.00/US\$50.00 | WTI \$ | — |
| 3-way option ⁽³⁾⁽⁴⁾ | Jan 2019 to Dec 2019 | 1,000 bbl/d | US\$75.50/US\$65.50/US\$55.50 | Brent \$ | — |
| Natural Gas | | | | | |
| Fixed - Sell | Jan 2018 to Dec 2018 | 10,000 mmbtu/d | US\$3.03 | NYMEX \$ | 0.9 |
| Fixed - Sell | Jan 2018 to Dec 2018 | 5,000 GJ/d | \$2.67 | AECO \$ | 2.1 |
| Fixed - Sell ⁽⁴⁾ | Feb 2018 to Dec 2018 | 5,000 mmbtu/d | US\$2.99 | NYMEX \$ | — |
| Total | | | | | \$ (31.6) |
| Current asset | | | | | \$ 18.5 |
| Current liability | | | | | \$ (50.1) |

(1) Based on the weighted average price per unit for the period.

(2) Fair values as at December 31, 2017. For the purposes of the table, contracts entered subsequent to December 31, 2017 will have no fair value assigned.

(3) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US\$60/US\$54.40/US\$40 contract, Baytex receives WTI plus US\$14.40/bbl when WTI is at or below US\$40/bbl; Baytex receives US\$54.40/bbl when WTI is between US\$40/bbl and US\$54.40/bbl; Baytex receives the market price when WTI is between US\$54.40/bbl and US\$60/bbl; and Baytex receives US\$60/bbl when WTI is above US\$60/bbl.

(4) Contracts entered subsequent to December 31, 2017.

(5) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

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

| | Years Ended December 31 | |
|---------------------------------------|-------------------------|-------------|
| | 2017 | 2016 |
| Realized financial derivatives gain | \$ (7,616) | \$ (96,929) |
| Unrealized financial derivatives loss | 2,439 | 140,136 |
| Financial derivatives (gain) loss | \$ (5,177) | \$ 43,207 |

Physical Delivery Contracts

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

| Period | Product | Volume | Price/Unit ⁽¹⁾ |
|----------------------|---------|-------------|---------------------------|
| Jan 2018 to Dec 2018 | WCS | 2,000 bbl/d | WTI less US\$14.00/bbl |

(1) Based on the weighted average price per unit for the period.

As at December 31, 2017, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

| Period | Volume |
|----------------------|-------------|
| Jan 2018 to Apr 2018 | 1,000 bbl/d |
| Jan 2018 to Dec 2018 | 5,000 bbl/d |
| Apr 2018 | 1,000 bbl/d |
| May 2018 to Dec 2018 | 2,000 bbl/d |

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures. As at December 31, 2017, Baytex had available unused bank credit facilities in the amount of \$494.6 million (as at December 31, 2016 - \$580.8 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2017 is outlined in the table below:

| | Total | Less than 1 year | 1-3 years | 3-5 years | Beyond 5 years |
|--------------------------------|--------------|------------------|------------|--------------|----------------|
| Trade and other payables | \$ 144,542 | \$ 144,542 | \$ — | \$ — | \$ — |
| Bank loan ^{(1) (2)} | 213,376 | — | 213,376 | — | — |
| Long-term notes ⁽²⁾ | 1,489,210 | — | — | 988,490 | 500,720 |
| Interest on long-term notes | 398,635 | 86,377 | 172,754 | 99,609 | 39,895 |
| | \$ 2,245,763 | \$ 230,919 | \$ 386,130 | \$ 1,088,099 | \$ 540,615 |

(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.

Credit Risk

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

The majority of the Company's credit exposure on accounts receivable at December 31, 2017 relates to accrued revenues for December 2017. Accounts receivables from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At December 31, 2017, US\$7.6 million of accounts receivable relates to joint interest receivables from the operator of our joint operations in the Eagle Ford.

Should Baytex determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. For the year ended December 31, 2017, the allowance for doubtful accounts increased by \$0.2 million (2016 - no change).

As at December 31, 2017, allowance for doubtful accounts was \$1.6 million (2016 - \$1.4 million). In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2017, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was \$0.7 million (2016 - \$0.9 million).

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2017:

| Trade and Other Receivables Aging | December 31, 2017 | |
|--|--------------------------|---------|
| Current (less than 30 days) | \$ | 107,796 |
| 31-60 days | | 2,939 |
| 61-90 days | | 1,427 |
| Past due (more than 90 days) | | 682 |
| | \$ | 112,844 |

19. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

| | Years Ended December 31 | |
|--|--------------------------------|--------------|
| | 2017 | 2016 |
| Trade and other receivables | \$ (673) | \$ (14,078) |
| Trade and other payables | 31,569 | (154,865) |
| Non-cash working capital acquired | (4,357) | — |
| | \$ 26,539 | \$ (168,943) |
| Changes in non-cash working capital related to: | | |
| Operating activities | \$ (8,962) | \$ (23,270) |
| Investing activities | 33,683 | (135,743) |
| Foreign currency translation on non-cash working capital | 1,818 | (9,930) |
| | \$ 26,539 | \$ (168,943) |

Onerous Contracts

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

| | Years Ended December 31 | |
|-----------------------------------|--------------------------------|-------------|
| | 2017 | 2016 |
| Balance, beginning of year | \$ 9,504 | \$ — |
| Liabilities incurred | — | 10,116 |
| Liabilities settled | (6,746) | (770) |
| Foreign currency translation | (184) | 158 |
| Balance, end of year | \$ 2,574 | \$ 9,504 |

As at December 31, 2017, the Company has a provision totaling \$2.6 million for an onerous contract related to an office sublease (December 31, 2016 - \$9.5 million related to an office sublease and a transportation agreement). The provision represents the difference between the minimum future payments that we are required to make and the estimated recoveries.

Income Statement Presentation

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

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

| | Years Ended December 31 | |
|--|-------------------------|------------------|
| | 2017 | 2016 |
| Operating | \$ 13,424 | \$ 9,528 |
| General and administrative | 36,086 | 23,070 |
| Total employee compensation costs | \$ 49,510 | \$ 32,598 |

20. COMMITMENTS AND CONTINGENCIES

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2017, and the expected timing of funding of these obligations, are noted in the table below.

| | Total | Less than 1 year | 1-3 years | 3-5 years | Beyond 5 years |
|---------------------------|-------------------|---------------------|------------------|------------------|------------------|
| Operating leases | \$ 29,926 | 7,727 | 13,510 | 8,689 | — |
| Processing agreements | 41,845 | 6,993 | 9,164 | 9,004 | 16,684 |
| Transportation agreements | 31,948 | 2,602 | 14,635 | 13,661 | 1,050 |
| Total | \$ 103,719 | \$ 17,322 | \$ 37,309 | \$ 31,354 | \$ 17,734 |

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statements of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2017 were \$6.5 million (December 31, 2016 - \$7.7 million). Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has the option to renew or extend the leases on its office building with the new lease terms to be based on current market prices. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

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

21. RELATED PARTIES

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

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

| | Years Ended December 31 | |
|--|-------------------------|------------------|
| | 2017 | 2016 |
| Short-term employee benefits | \$ 7,840 | \$ 7,278 |
| Share-based compensation | 3,569 | 6,613 |
| Termination payments | 275 | — |
| Total compensation for key management personnel | \$ 11,684 | \$ 13,891 |

22. CAPITAL DISCLOSURES

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions and the risk characteristics of our oil and gas properties. At December 31, 2017, our capital structure was comprised of shareholders' capital, long-term debt, working capital and the bank loan.

Baytex monitors capital based on the ratio of net debt to adjusted funds flow and the level of undrawn credit facilities. The Company's adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The Company's Revolving 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. At December 31, 2017, Baytex was in compliance with all of the covenants contained in the Revolving Facilities and had unused capacity of \$494.6 million.

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, the Company uses a ratio of net debt to adjusted funds flow to manage its capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Adjusted funds flow 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 or loss.

Adjusted funds flow is reconciled to the nearest measure determined in accordance with IFRS, cash flow from operating activities, as set forth below.

| | Years Ended December 31 | |
|--------------------------------------|-------------------------|------------|
| | 2017 | 2016 |
| Cash flow from operating activities | \$ 325,208 | \$ 247,365 |
| Change in non-cash working capital | 8,962 | 23,270 |
| Asset retirement obligations settled | 13,471 | 5,616 |
| Adjusted funds flow | \$ 347,641 | \$ 276,251 |

Net debt does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measure for other entities. The computation of net debt is set forth below.

| | As at December 31 | |
|-----------------------------|-------------------|--------------|
| | 2017 | 2016 |
| Bank loan - principal | \$ 213,376 | \$ 191,286 |
| Long-term notes - principal | 1,489,210 | 1,584,158 |
| Trade and other payables | 144,542 | 112,973 |
| Cash | — | (2,705) |
| Trade and other receivables | (112,844) | (112,171) |
| Net debt | \$ 1,734,284 | \$ 1,773,541 |

Availability under the Company's existing Revolving Facilities and the computed net debt to adjusted funds flow ratio as at December 31, 2017 and 2016 is set forth below.

| | As at December 31 | |
|---------------------------------------|-------------------|------------|
| | 2017 | 2016 |
| Available undrawn credit facilities | \$ 494,634 | \$ 580,767 |
| Net debt to adjusted funds flow ratio | 5.0 | 6.4 |

We utilized the Revolving Facilities to close the property acquisition (note 4) on January 20, 2017 which reduced the undrawn amount of the credit facility at December 31, 2017 as compared to December 31, 2016.

The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2016 is attributed to higher adjusted funds flow from improved commodity prices and higher annual production in 2017, along with a decrease in net debt as at December 31, 2017.

Petroleum and Natural Gas Reserves as at December 31, 2017

Baytex's year-end 2017 proved and probable reserves were evaluated by Sproule Unconventional Limited ("Sproule") and Ryder Scott Company, L.P. ("Ryder Scott"), both independent qualified reserves evaluators. Sproule prepared our reserves report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's December 31, 2017 forecast price and cost assumptions. Ryder Scott also evaluated the possible reserves associated with our Eagle Ford assets. All Baytex oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Finding and development ("F&D") and finding, development and acquisition ("FD&A") costs are all reported inclusive of future development costs ("FDC").

The following table sets forth our gross and net reserves volumes at December 31, 2017 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

| CANADA | Forecast Prices and Costs | | | | | |
|----------------------------|--------------------------------|------------------------------|--------------------------------|------------------------------|--------------------------------|------------------------------|
| | Heavy Oil | | Bitumen | | Light and Medium Oil | |
| | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) |
| Reserves Category | | | | | | |
| Proved | | | | | | |
| Developed Producing | 26,276 | 20,748 | 94 | 92 | 1,482 | 1,441 |
| Developed Non-Producing | 1,750 | 1,498 | 7,744 | 7,072 | 1 | 1 |
| Undeveloped | 18,680 | 16,608 | 5,428 | 4,546 | 125 | 122 |
| Total Proved | 46,706 | 38,854 | 13,266 | 11,709 | 1,608 | 1,564 |
| Probable | 39,757 | 33,563 | 55,726 | 43,833 | 1,225 | 1,090 |
| Total Proved Plus Probable | 86,463 | 72,417 | 68,992 | 55,542 | 2,833 | 2,654 |

| CANADA | Forecast Prices and Costs | | | | | |
|----------------------------|------------------------------------|------------------------------|---|------------------------------|--------------------------------|------------------------------|
| | Natural Gas Liquids ⁽³⁾ | | Conventional Natural Gas ⁽⁴⁾ | | Oil Equivalent ⁽⁵⁾ | |
| | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) | Gross ⁽¹⁾ (mmcf) | Net ⁽²⁾ (mmcf) | Gross ⁽¹⁾ (mboe) | Net ⁽²⁾ (mboe) |
| Reserves Category | | | | | | |
| Proved | | | | | | |
| Developed Producing | 1,075 | 761 | 43,929 | 37,680 | 36,249 | 29,322 |
| Developed Non-Producing | 21 | 12 | 27,034 | 25,309 | 14,021 | 12,801 |
| Undeveloped | 1,522 | 1,228 | 46,856 | 41,080 | 33,564 | 29,351 |
| Total Proved | 2,618 | 2,002 | 117,819 | 104,069 | 83,834 | 71,474 |
| Probable | 3,132 | 2,428 | 89,963 | 77,782 | 114,834 | 93,878 |
| Total Proved Plus Probable | 5,750 | 4,430 | 207,782 | 181,853 | 198,667 | 165,352 |

| UNITED STATES | Forecast Prices and Costs | | | | | |
|--|--------------------------------|------------------------------|------------------------------------|------------------------------|--------------------------------|------------------------------|
| | Tight Oil | | Natural Gas Liquids ⁽³⁾ | | Shale Gas | |
| | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) | Gross ⁽¹⁾ (mdbl) | Net ⁽²⁾ (mdbl) | Gross ⁽¹⁾ (mmcf) | Net ⁽²⁾ (mmcf) |
| Reserves Category | | | | | | |
| Proved | | | | | | |
| Developed Producing | 20,191 | 14,809 | 28,052 | 20,742 | 61,139 | 45,273 |
| Developed Non-Producing | 32 | 23 | 111 | 81 | 209 | 152 |
| Undeveloped | 30,074 | 22,022 | 53,784 | 39,590 | 111,506 | 82,186 |
| Total Proved | 50,296 | 36,854 | 81,947 | 60,413 | 172,855 | 127,611 |
| Probable | 11,390 | 8,361 | 35,830 | 26,333 | 75,686 | 55,607 |
| Total Proved Plus Probable | 61,686 | 45,215 | 117,777 | 86,745 | 248,541 | 183,218 |
| Possible ⁽⁶⁾ | 19,992 | 14,679 | 41,964 | 30,862 | 89,370 | 65,736 |
| Total Proved Plus Probable Plus Possible | 81,679 | 59,894 | 159,741 | 117,607 | 337,910 | 248,954 |

UNITED STATES

| <u>Reserves Category</u> |
|--|
| Proved |
| Developed Producing |
| Developed Non-Producing |
| Undeveloped |
| Total Proved |
| Probable |
| Total Proved Plus Probable |
| Possible ⁽⁶⁾ |
| Total Proved Plus Probable Plus Possible |

Forecast Prices and Costs

| <u>Conventional Natural Gas⁽⁴⁾</u> | | <u>Oil Equivalent⁽⁵⁾</u> | |
|---|--------------------------|-------------------------------------|--------------------------|
| <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> | <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> |
| <u>(mmcf)</u> | <u>(mmcf)</u> | <u>(mboe)</u> | <u>(mdbl)</u> |
| 34,115 | 25,076 | 64,119 | 47,276 |
| 91 | 65 | 193 | 140 |
| 29,812 | 21,794 | 107,410 | 78,942 |
| 64,018 | 46,935 | 171,722 | 126,358 |
| 10,761 | 7,900 | 61,628 | 45,278 |
| 74,778 | 54,835 | 233,349 | 171,635 |
| 19,577 | 14,372 | 80,115 | 58,892 |
| 94,356 | 69,207 | 313,464 | 230,528 |

TOTAL

| <u>Reserves Category</u> |
|--|
| Proved |
| Developed Producing |
| Developed Non-Producing |
| Undeveloped |
| Total Proved |
| Probable |
| Total Proved Plus Probable |
| Possible ⁽⁶⁾⁽⁷⁾ |
| Total Proved Plus Probable Plus Possible |

Forecast Prices and Costs

| <u>Heavy Oil</u> | | <u>Bitumen</u> | | <u>Light and Medium Oil</u> | |
|----------------------------|--------------------------|----------------------------|--------------------------|-----------------------------|--------------------------|
| <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> | <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> | <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> |
| <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> |
| 26,276 | 20,748 | 94 | 92 | 1,482 | 1,441 |
| 1,750 | 1,498 | 7,744 | 7,072 | 1 | 1 |
| 18,680 | 16,608 | 5,428 | 4,546 | 125 | 122 |
| 46,706 | 38,854 | 13,266 | 11,709 | 1,608 | 1,564 |
| 39,757 | 33,563 | 55,726 | 43,833 | 1,225 | 1,090 |
| 86,463 | 72,417 | 68,992 | 55,542 | 2,833 | 2,654 |
| — | — | — | — | — | — |
| 86,463 | 72,417 | 68,992 | 55,542 | 2,833 | 2,654 |

TOTAL

| <u>Reserves Category</u> |
|--|
| Proved |
| Developed Producing |
| Developed Non-Producing |
| Undeveloped |
| Total Proved |
| Probable |
| Total Proved Plus Probable |
| Possible ⁽⁶⁾⁽⁷⁾ |
| Total Proved Plus Probable Plus Possible |

Forecast Prices and Costs

| <u>Tight Oil</u> | | <u>Natural Gas Liquids⁽³⁾</u> | | <u>Shale Gas</u> | |
|----------------------------|--------------------------|--|--------------------------|----------------------------|--------------------------|
| <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> | <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> | <u>Gross⁽¹⁾</u> | <u>Net⁽²⁾</u> |
| <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mdbl)</u> | <u>(mmcf)</u> | <u>(mmcf)</u> |
| 20,191 | 14,809 | 29,128 | 21,503 | 61,139 | 45,273 |
| 32 | 23 | 131 | 93 | 209 | 152 |
| 30,074 | 22,022 | 55,306 | 40,818 | 111,506 | 82,186 |
| 50,296 | 36,854 | 84,564 | 62,414 | 172,855 | 127,611 |
| 11,390 | 8,361 | 38,962 | 28,760 | 75,686 | 55,607 |
| 61,686 | 45,215 | 123,526 | 91,175 | 248,541 | 183,218 |
| 19,992 | 14,679 | 41,964 | 30,862 | 89,370 | 65,736 |
| 81,679 | 59,894 | 165,491 | 122,037 | 337,910 | 248,954 |

TOTAL**Forecast Prices and Costs**

| Reserves Category | Conventional Natural Gas⁽⁴⁾ | | Oil Equivalent⁽⁵⁾ | |
|--|---|--------------------------|-------------------------------------|--------------------------|
| | Gross⁽¹⁾ | Net⁽²⁾ | Gross⁽¹⁾ | Net⁽²⁾ |
| | (mmcf) | (mmcf) | (mboe) | (mboe) |
| Proved | | | | |
| Developed Producing | 78,045 | 62,756 | 100,368 | 76,598 |
| Developed Non-Producing | 27,125 | 25,374 | 14,214 | 12,941 |
| Undeveloped | 76,668 | 62,874 | 140,974 | 108,293 |
| Total Proved | 181,837 | 151,004 | 255,556 | 197,831 |
| Probable | 100,723 | 85,683 | 176,461 | 139,155 |
| Total Proved Plus Probable | 282,561 | 236,687 | 432,017 | 336,987 |
| Possible ⁽⁶⁾⁽⁷⁾ | 19,577 | 14,372 | 80,115 | 58,892 |
| Total Proved Plus Probable Plus Possible | 302,138 | 251,059 | 512,131 | 395,879 |

Notes:

- (1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
- (2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.
- (3) Natural Gas Liquids includes condensate.
- (4) Conventional Natural Gas includes associated, non-associated and solution gas.
- (5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (6) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
- (7) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Reserves Reconciliation

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

**Reconciliation of Gross Reserves⁽¹⁾⁽²⁾
By Principal Product Type
Forecast Prices and Costs**

| Gross Reserves Category | Heavy Oil | | | Bitumen | | |
|--------------------------------|--------------------------|----------------------------|---|--------------------------|----------------------------|---|
| | Proved (mdbl) | Probable (mdbl) | Proved + Probable (mdbl) | Proved (mdbl) | Probable (mdbl) | Proved + Probable (mdbl) |
| December 31, 2016 | 46,875 | 29,325 | 76,199 | 13,465 | 55,835 | 69,300 |
| Extensions | 638 | 500 | 1,138 | — | — | — |
| Infill Drilling | 369 | 364 | 732 | — | — | — |
| Improved Recoveries | — | 1,997 | 1,997 | — | — | — |
| Technical Revisions | 1,121 | (2,861) | (1,740) | 197 | (142) | 55 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions ⁽³⁾ | 7,941 | 11,334 | 19,275 | — | — | — |
| Dispositions | (1,221) | (974) | (2,195) | — | — | — |
| Economic Factors | (89) | 73 | (16) | (80) | 33 | (47) |
| Production | (8,927) | — | (8,927) | (317) | — | (317) |
| December 31, 2017 | 46,706 | 39,757 | 86,463 | 13,266 | 55,726 | 68,992 |

| Gross Reserves Category | Light and Medium Crude Oil | | | Tight Oil | | |
|------------------------------------|----------------------------|--------------------|--------------------------------|------------------|--------------------|--------------------------------|
| | Proved (mdbl) | Probable (mdbl) | Proved + Probable (mdbl) | Proved (mdbl) | Probable (mdbl) | Proved + Probable (mdbl) |
| December 31, 2016 | 2,293 | 1,794 | 4,087 | 49,714 | 8,399 | 58,113 |
| Extensions | — | — | — | — | — | — |
| Infill Drilling | — | — | — | 1,307 | 2,252 | 3,559 |
| Improved Recoveries | — | — | — | — | — | — |
| Technical Revisions ⁽⁴⁾ | 422 | 31 | 453 | 3,821 | 736 | 4,557 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | — | — | — | — | — | — |
| Dispositions | (720) | (559) | (1,279) | — | — | — |
| Economic Factors | 38 | (41) | (3) | 8 | 3 | 11 |
| Production | (425) | — | (425) | (4,553) | — | (4,553) |
| December 31, 2017 | 1,608 | 1,225 | 2,833 | 50,296 | 11,390 | 61,686 |

| Gross Reserves Category | Natural Gas Liquids ⁽⁵⁾ | | | Shale Gas | | |
|------------------------------------|------------------------------------|--------------------|--------------------------------|------------------|--------------------|--------------------------------|
| | Proved (mdbl) | Probable (mdbl) | Proved + Probable (mdbl) | Proved (mmcf) | Probable (mmcf) | Proved + Probable (mmcf) |
| December 31, 2016 | 82,692 | 31,825 | 114,516 | 173,828 | 59,075 | 232,903 |
| Extensions | 90 | 224 | 314 | — | — | — |
| Infill Drilling | 1,393 | 1,095 | 2,488 | 2,096 | 6,464 | 8,560 |
| Improved Recoveries | — | — | — | — | — | — |
| Technical Revisions ⁽⁴⁾ | 6,487 | 5,758 | 12,245 | 7,590 | 10,190 | 17,781 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 115 | 81 | 196 | — | — | — |
| Dispositions | — | — | — | — | — | — |
| Economic Factors | (50) | (21) | (71) | (133) | (43) | (177) |
| Production | (6,162) | — | (6,162) | (10,526) | — | (10,526) |
| December 31, 2017 | 84,564 | 38,962 | 123,526 | 172,855 | 75,686 | 248,541 |

| Gross Reserves Category | Conventional Natural Gas ⁽⁶⁾ | | | Oil Equivalent ⁽⁷⁾ | | |
|------------------------------------|---|--------------------|--------------------------------|-------------------------------|--------------------|--------------------------------|
| | Proved (mmcf) | Probable (mmcf) | Proved + Probable (mmcf) | Proved (mboe) | Probable (mboe) | Proved + Probable (mboe) |
| December 31, 2016 | 172,016 | 98,112 | 270,127 | 252,679 | 153,375 | 406,053 |
| Extensions | 2,067 | 5,042 | 7,109 | 1,073 | 1,564 | 2,637 |
| Infill Drilling | 3,421 | 845 | 4,266 | 3,987 | 4,929 | 8,916 |
| Improved Recoveries | — | — | — | — | 1,997 | 1,997 |
| Technical Revisions ⁽⁴⁾ | 21,703 | (6,086) | 15,617 | 16,931 | 4,206 | 21,137 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions ⁽³⁾ | 4,241 | 3,008 | 7,249 | 8,763 | 11,916 | 20,679 |
| Dispositions | (2) | (2) | (4) | (1,942) | (1,534) | (3,475) |
| Economic Factors | (608) | (195) | (803) | (296) | 8 | (289) |
| Production | (21,001) | — | (21,001) | (25,639) | — | (25,639) |
| December 31, 2017 | 181,837 | 100,724 | 282,560 | 255,556 | 176,461 | 432,017 |

Notes:

- (1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
- (2) Reserves information as at December 31, 2017 and 2016 is prepared in accordance with NI 51-101.
- (3) Heavy oil and conventional natural gas acquisitions are principally attributable to reserves associated with the Peace River assets acquired on January 20, 2017.
- (4) Positive technical revisions for tight oil, natural gas liquids and shale gas are largely the result of enhanced type well profiles on our Eagle Ford acreage.
- (5) Natural gas liquids include condensate.
- (6) Conventional natural gas includes associated, non-associated and solution gas.

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

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves (excluding thermal reserves) at year-end 2017 by annualized Q4/2017 production.

| | Q4/2017 Actual Production | Reserves Life Index (years) | |
|------------------------|------------------------------|-----------------------------|----------------------|
| | | Proved | Proved Plus Probable |
| Oil and NGL (bbl/d) | 56,046 | 9.0 | 13.4 |
| Natural Gas (mcf/d) | 81,063 | 12.0 | 17.9 |
| Oil Equivalent (boe/d) | 69,556 | 9.5 | 14.3 |

Capital Program Efficiency

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

| | 2017 | 2016 | 2015 | Three-Year Total / Average 2015 - 2017 |
|---|------------|---------------------|------------|--|
| Capital Expenditures (\$ millions) | | | | |
| Exploration and development | \$ 326.3 | \$ 224.8 | \$ 521.0 | \$ 1,072.1 |
| Acquisitions (net of dispositions) | 59.9 | (63.6) | 1.6 | (2.1) |
| Total | \$ 386.1 | \$ 161.2 | \$ 522.7 | \$ 1,070.0 |
| Change in Future Development Costs – Proved (\$ millions) | | | | |
| Exploration and development | \$ (132.6) | \$ (219.4) | \$ (397.9) | \$ (749.9) |
| Acquisitions (net of dispositions) | 35.5 | 7.6 | 6.0 | 49.1 |
| Total | \$ (97.1) | \$ (211.8) | \$ (391.9) | \$ (700.8) |
| Change in Future Development Costs – Proved plus Probable (\$ millions) | | | | |
| Exploration and Development | \$ (76.4) | \$ 108.8 | \$ (399.9) | \$ (367.5) |
| Acquisitions (net of dispositions) | 160.6 | 1.9 | 0.5 | 163.0 |
| Total | \$ 84.2 | \$ 110.7 | \$ (399.4) | \$ (204.5) |
| Proved Reserves Additions (mboe) | | | | |
| Exploration and development | 21,695 | 5,041 | 21,729 | 48,465 |
| Acquisitions (net of dispositions) | 6,821 | (1,564) | 537 | 5,794 |
| Total | 28,516 | 3,477 | 22,266 | 54,259 |
| Proved plus Probable Reserves Additions (mboe) | | | | |
| Exploration and development | 34,398 | 17,253 | 15,782 | 67,433 |
| Acquisitions (net of dispositions) | 17,204 | (2,408) | 126 | 14,922 |
| Total | 51,602 | 14,845 | 15,908 | 82,355 |
| F&D costs (\$/boe) ⁽¹⁾ | | | | |
| Proved | \$ 8.93 | \$ 1.07 | \$ 5.67 | \$ 6.65 |
| Proved plus probable | \$ 7.26 | \$ 19.33 | \$ 7.68 | \$ 10.45 |
| FD&A costs (\$/boe) ⁽²⁾ | | | | |
| Proved | \$ 10.13 | \$ — ⁽⁵⁾ | \$ 5.88 | \$ 6.80 |
| Proved plus probable | \$ 9.11 | \$ 18.33 | \$ 7.75 | \$ 10.51 |
| Ratios (based on proved plus probable reserves) | | | | |
| Production replacement ratio ⁽³⁾ | 201% | 58% | 52% | 100% |
| Recycle ratio ⁽⁴⁾ | 2.7x | 0.9x | 2.9x | 2.2x |

Notes:

- (1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures and including the change in FDC) divided by reserves additions from exploration and development activity.
- (2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures and the change in FDC) divided by total reserves additions.
- (3) Production Replacement Ratio is calculated as total reserves additions (including acquisitions and divestitures) divided by annual production.
- (4) Recycle Ratio is calculated as operating netback divided by F&D costs (proved plus probable). Operating netback is calculated as revenue (including realized financial derivatives gains and losses) less royalties, operating expenses and transportation expenses.
- (5) 2016 FD&A costs (proved) were negative due to the reduction in estimated Future Development Costs.

Net Present Value of Reserves (Forecast Prices and Costs)

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

Summary of Net Present Value of Future Net Revenue As at December 31, 2017 Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)

CANADA

| Reserves Category | 0% (\$000s) | 5% (\$000s) | 10% (\$000s) | 15% (\$000s) | 20% (\$000s) |
|----------------------------|----------------|----------------|-----------------|-----------------|-----------------|
| Proved | | | | | |
| Developed Producing | \$ 394,678 | \$ 392,339 | \$ 359,063 | \$ 327,713 | \$ 300,965 |
| Developed Non-Producing | 322,386 | 195,869 | 135,648 | 98,310 | 73,393 |
| Undeveloped | 475,480 | 362,040 | 278,773 | 216,443 | 168,923 |
| Total Proved | 1,192,544 | 950,248 | 773,484 | 642,465 | 543,281 |
| Probable | 2,428,609 | 1,326,481 | 806,284 | 526,528 | 360,482 |
| Total Proved Plus Probable | \$ 3,621,153 | \$ 2,276,730 | \$ 1,579,768 | \$ 1,168,994 | \$ 903,763 |

UNITED STATES

| Reserves Category | 0% (\$000s) | 5% (\$000s) | 10% (\$000s) | 15% (\$000s) | 20% (\$000s) |
|---|----------------|----------------|-----------------|-----------------|-----------------|
| Proved | | | | | |
| Developed Producing | \$ 1,771,167 | \$ 1,311,579 | \$ 1,045,543 | \$ 875,040 | \$ 757,316 |
| Developed Non-Producing | 4,334 | 3,227 | 2,537 | 2,080 | 1,763 |
| Undeveloped | 2,492,733 | 1,523,326 | 1,009,941 | 705,898 | 510,856 |
| Total Proved | 4,268,233 | 2,838,131 | 2,058,020 | 1,583,018 | 1,269,934 |
| Probable | 1,679,658 | 812,362 | 452,804 | 276,144 | 178,484 |
| Total Proved Plus Probable | 5,947,892 | 3,650,494 | 2,510,824 | 1,859,162 | 1,448,419 |
| Possible ⁽¹⁾ | 2,750,546 | 1,581,035 | 1,046,186 | 752,174 | 570,766 |
| Total Proved Plus Probable Plus Possible ⁽¹⁾ | \$ 8,698,438 | \$ 5,231,529 | \$ 3,557,009 | \$ 2,611,337 | \$ 2,019,185 |

TOTAL

| Reserves Category | 0% (\$000s) | 5% (\$000s) | 10% (\$000s) | 15% (\$000s) | 20% (\$000s) |
|--|----------------|----------------|-----------------|-----------------|-----------------|
| Proved | | | | | |
| Developed Producing | \$ 2,165,845 | \$ 1,703,918 | \$ 1,404,606 | \$ 1,202,752 | \$ 1,058,281 |
| Developed Non-Producing | 326,719 | 199,096 | 138,185 | 100,390 | 75,156 |
| Undeveloped | 2,968,213 | 1,885,366 | 1,288,713 | 922,341 | 679,779 |
| Total Proved | 5,460,777 | 3,788,380 | 2,831,504 | 2,225,483 | 1,813,216 |
| Probable | 4,108,268 | 2,138,844 | 1,259,087 | 802,673 | 538,966 |
| Total Proved Plus Probable | 9,569,045 | 5,927,224 | 4,090,592 | 3,028,156 | 2,352,182 |
| Possible ⁽¹⁾⁽²⁾ | 2,750,546 | 1,581,035 | 1,046,186 | 752,174 | 570,766 |
| Total Proved Plus Probable Plus Possible ⁽¹⁾⁽²⁾ | \$ 12,319,591 | \$ 7,508,259 | \$ 5,136,777 | \$ 3,780,330 | \$ 2,922,948 |

Notes:

- (1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
- (2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2017.

| Year | WTI Cushing US\$/bbl | Canadian Light Sweet C\$/bbl | Western Canada Select C\$/bbl | Henry Hub US\$/MMbtu | AECO-C Spot C\$/MMbtu | Operating Cost Inflation Rate %/Yr | Capital Cost Inflation Rate %/Yr | Exchange Rate \$US/\$Cdn |
|------------|-------------------------|------------------------------------|-------------------------------------|-------------------------|--------------------------|--|--|-----------------------------|
| 2017 act. | 50.95 | 61.84 | 48.78 | 3.02 | 2.20 | 2.2 | (3.4) | 0.771 |
| 2018 | 55.00 | 65.44 | 51.05 | 3.25 | 2.85 | 0.0 | 0.0 | 0.790 |
| 2019 | 65.00 | 74.51 | 59.61 | 3.50 | 3.11 | 2.0 | 2.0 | 0.820 |
| 2020 | 70.00 | 78.24 | 64.94 | 4.00 | 3.65 | 2.0 | 2.0 | 0.850 |
| 2021 | 73.00 | 82.45 | 68.43 | 4.08 | 3.80 | 2.0 | 2.0 | 0.850 |
| 2022 | 74.46 | 84.10 | 69.80 | 4.16 | 3.95 | 2.0 | 2.0 | 0.850 |
| 2023 | 75.95 | 85.78 | 71.20 | 4.24 | 4.05 | 2.0 | 2.0 | 0.850 |
| 2024 | 77.47 | 87.49 | 72.62 | 4.33 | 4.15 | 2.0 | 2.0 | 0.850 |
| 2025 | 79.02 | 89.24 | 74.07 | 4.42 | 4.25 | 2.0 | 2.0 | 0.850 |
| 2026 | 80.60 | 91.03 | 75.55 | 4.50 | 4.36 | 2.0 | 2.0 | 0.850 |
| 2027 | 82.21 | 92.85 | 77.06 | 4.59 | 4.46 | 2.0 | 2.0 | 0.850 |
| 2028 | 83.86 | 94.71 | 78.61 | 4.69 | 4.57 | 2.0 | 2.0 | 0.850 |
| Thereafter | Escalation rate of 2.0% | | | | | | | |

Future Development Costs

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

| | Future Development Costs As of December 31, 2017 Forecast Prices and Costs (\$000s) | | | | | |
|----------------------|--|-------------------------------------|--------------------|-------------------------------------|--------------------|-------------------------------------|
| | CANADA | | UNITED STATES | | TOTAL | |
| | Proved Reserves | Proved plus Probable Reserves | Proved Reserves | Proved plus Probable Reserves | Proved Reserves | Proved plus Probable Reserves |
| 2018 | 98,043 | 126,225 | 136,837 | 149,937 | 234,879 | 276,163 |
| 2019 | 155,071 | 188,546 | 311,259 | 315,979 | 466,330 | 504,524 |
| 2020 | 133,323 | 357,593 | 302,301 | 316,986 | 435,624 | 674,579 |
| 2021 | 6,348 | 263,674 | 232,243 | 297,916 | 238,591 | 561,590 |
| 2022 | 12,401 | 122,321 | 146,451 | 249,786 | 158,852 | 372,107 |
| Remaining | 1,734 | 309,933 | 141,785 | 471,862 | 143,519 | 781,794 |
| Total (undiscounted) | 406,921 | 1,368,291 | 1,270,875 | 1,802,465 | 1,677,796 | 3,170,757 |

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2017.

| | Undeveloped Acres | |
|----------------------|-------------------|---------|
| | Gross | Net |
| Canada | | |
| Alberta | 748,920 | 688,166 |
| Saskatchewan | 111,360 | 105,901 |
| Total Canada | 860,280 | 794,067 |
| United States | | |
| Texas | 117 | 102 |
| Total Company | 860,397 | 794,169 |

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2017. We estimate the value of our net undeveloped land holdings at December 31, 2017 to be approximately \$75.9 million, as compared to \$67.1 million as at December 31, 2016. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries, net of undeveloped acreage that has reserves value attributed.

Net Asset Value

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

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

The following table sets forth our net asset value as at December 31, 2017.

| (\$ millions except per share amounts) | Net Asset Value Forecast Prices and Costs Before Income Taxes and Discounted at (%/year) | | |
|---|--|----------|----------|
| | 5% | 10% | 15% |
| Total net present value of proved plus probable reserves (before tax) | \$ 5,927 | \$ 4,091 | \$ 3,028 |
| Undeveloped land holdings ⁽¹⁾ | 76 | 76 | 76 |
| Asset retirement obligations ⁽²⁾ | (122) | (59) | (42) |
| Net debt | (1,734) | (1,734) | (1,734) |
| Net Asset Value | \$ 4,147 | \$ 2,374 | \$ 1,328 |
| Net Asset Value per Share ⁽³⁾ | \$ 17.61 | \$ 10.08 | \$ 5.64 |

Notes:

- (1) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
- (2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.
- (3) Based on 235.5 million common shares outstanding as at December 31, 2017.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Lloydminster, Peace River, North East Alberta and Pembina areas in Canada. We commissioned Ryder Scott to audit our internal evaluation of our contingent resources in the Eagle Ford area of Texas. Both assessments were effective December 31, 2017, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

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

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

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

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

Development Pending

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

Development Pending - Project Status

| Area | Product Type | Project Status | Future Development Costs (\$ millions) ⁽¹⁾ | Timing of First Commercial Production | Recovery Technology |
|--|---------------------------------|-----------------|---|---------------------------------------|--|
| Peace River | Bitumen | Pre-Development | \$127 | 2019-2021 | Cyclic steam stimulation (“CSS”) |
| Peace River, Lloydminster and North East Alberta | Heavy Oil | Pre-Development | \$227 | 2018-2023 | Horizontal, vertical and multilateral well and polymer flood development |
| Pembina | Light & Medium Oil, Natural Gas | Pre-Development | \$5 | 2022 | Horizontal well development with multi-stage fracturing completion |
| Eagle Ford | Tight Oil, Shale Gas and NGL | Pre-Development | \$128 | 2018-2028 | Horizontal well development with multi-stage fracturing completion |

Note:

(1) Undiscounted and unrisks.

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

Development Pending - Chance of Development Risk ⁽¹⁾

| Area | Product Type | Unrisked (MMboe) | Chance of Development | Risked (MMboe) | Risked NPV ⁽²⁾ Discounted at 10% (before tax) (\$ millions) |
|---|--|---------------------|--------------------------|-------------------|---|
| Peace River | Bitumen | 19 | 81% | 16 | 86 |
| Peace River, Lloydminster and North East Alberta | Heavy Oil | 15 | 88% | 13 | 46 |
| Pembina | Light & Medium Oil and Natural Gas | 1 | 90% | 1 | 4 |
| Eagle Ford | Tight Oil, Shale Gas and NGL | 14 | 80% | 11 | 100 |
| Total | | 49 | | 41 | 236 |

Notes:

(1) Numbers may not add due to rounding.

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

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

Development Unclarified

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

Development Unclarified - Chance of Development Risk ⁽¹⁾

| Area | Product Type | Unrisked (MMboe) | Chance of Development | Risked (MMboe) |
|--|------------------------------------|------------------|-----------------------|----------------|
| Peace River and North East Alberta | Bitumen | 944 | 58% | 552 |
| Peace River, Lloydminster and North East Alberta | Heavy Oil | 32 | 57% | 18 |
| Pembina | Light & Medium Oil and Natural Gas | 12 | 55% | 7 |
| Eagle Ford | Tight Oil, Shale Gas and NGL | 135 | 50% | 67 |
| Total | | 1,123 | | 644 |

Note:

(1) Numbers may not add due to rounding.

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

Additional disclosures related to our contingent resources will be included in Appendix A to our Annual Information Form for the year ended December 31, 2017, which will be filed on or before March 31, 2018.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2017, which will be filed on or before March 31, 2018. Listed below are cautionary statements that are specifically required by NI 51-101:

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

This report contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio," "operating netback," and "reserves life index." These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this report to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not

reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

This report contains estimates as of December 31, 2017 of the volumes of "contingent resources" attributable to our properties. These estimates were prepared by independent qualified reserves evaluators.

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

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

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

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

Notice to United States Readers

The petroleum and natural gas reserves contained in this report have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves" and permits the optional disclosure of "possible reserves". Additionally, NI 51-101 defines "proved reserves", "probable reserves" and "possible reserves" differently from the SEC rules. Accordingly, proved, probable and possible reserves disclosed in this report may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. Possible reserves are higher risk than probable reserves and are generally believed to be less likely to be accurately estimated or recovered than probable reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this report may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

We also included in this report estimates of contingent resources. Contingent resources represent the quantity of petroleum and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The SEC does not permit the inclusion of estimates of resource in reports filed with it by United States companies.

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

ABBREVIATIONS

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

James L. Bowzer⁽³⁾
Independent Businessman

John A. Brussa
Chairman
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Independent Businessman

Trudy M. Curran⁽¹⁾⁽²⁾⁽⁴⁾
Independent Businesswoman

Naveen Dargan⁽¹⁾⁽²⁾
Independent Businessman

R.E.T. (Rusty) Goepel
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 Human Resources
and Compensation Committee

(3) Member of the Reserves Committee

(4) Member of the Nominating
and Governance Committee

OFFICERS

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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
& Public Affairs

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

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

Ryan M. Johnson
Vice President, Peace River
Business Unit

Chad L. Kalmakoff
Vice President, Finance

M. Scott Lovett
Vice President, Business Development

Gregory A. Sawchenko
Vice President, Land

AUDITORS

KPMG LLP

BANKERS

Bank of Nova Scotia
Alberta Treasury Branches
Bank of America
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company, L.P.

TRANSFER AGENT

Computershare Trust
Company of Canada

EXCHANGE LISTINGS

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

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