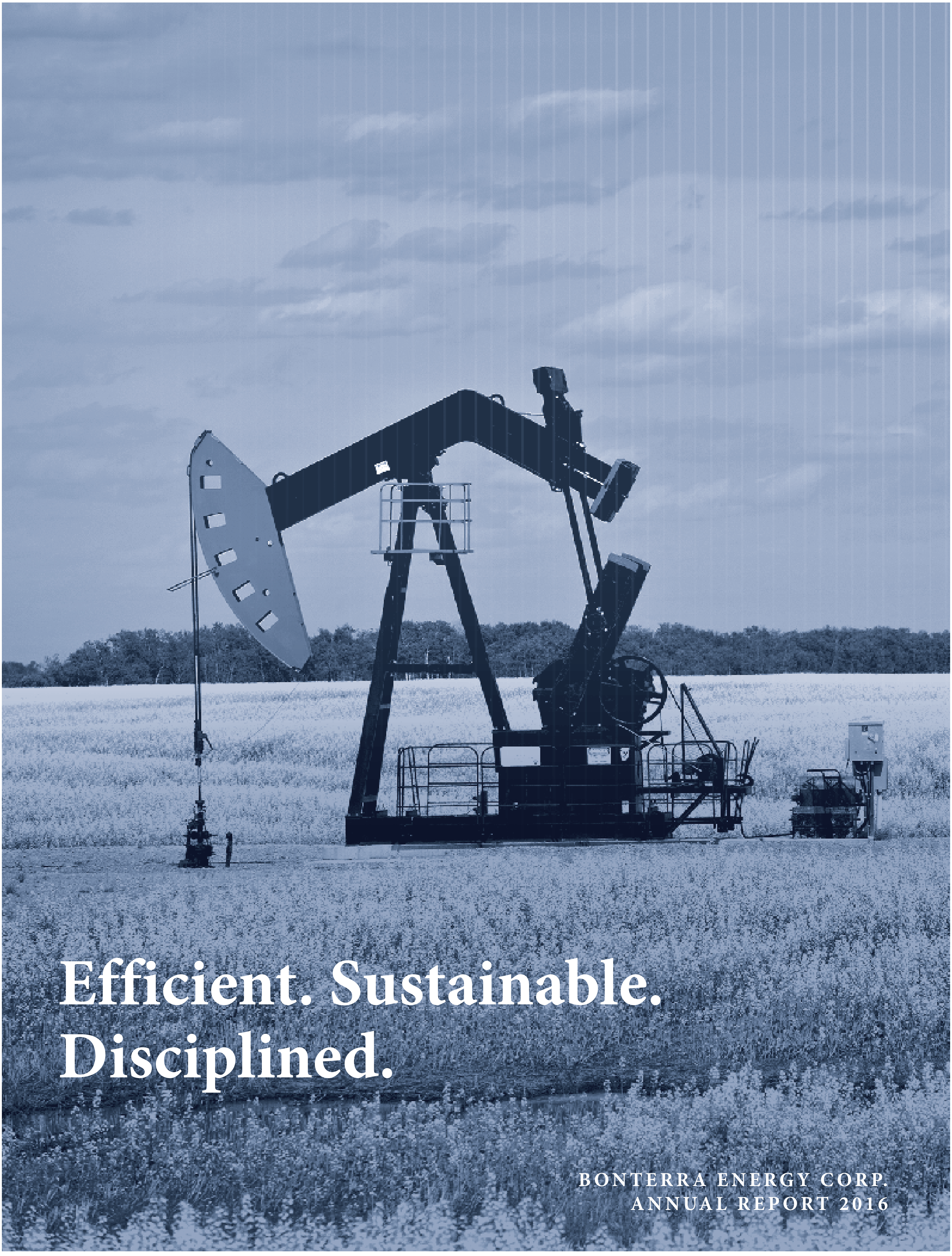

# Efficient. Sustainable. Disciplined.

BONTERRA ENERGY CORP.
ANNUAL REPORT 2016

# Focused on Fundamentals.

ANNUAL REPORT 2016

Bonterra Energy Corp. is a dividend-paying, conventional oil and gas company focused on growing funds flow, production and reserves on a per share basis. With a high-quality asset base, conservative financial management, and strong capital efficiencies, Bonterra is well positioned to deliver long-term sustainable growth.

Through 2016, Bonterra continued to realize operational success by focusing on projects that offer the highest economics within a persistently low commodity price environment. Ongoing success was realized in its core Pembina Cardium area in 2016 and the Company maintained stable production volumes due to successful drilling, the implementation of innovative completions techniques and its very low corporate decline rate of approximately 18 to 20 percent.


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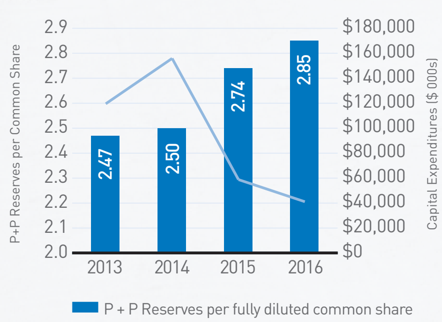
## GROWING P+P RESERVES PER SHARE WHILE EXECUTING A DISCIPLINED CAPITAL PLAN

### P + P RESERVES PER SHARE AND CAPITAL EXPENDITURES[(1)]




(1) Capital expenditures net of dispositions

- 3% increase in P+P reserves per fully diluted common share in 2016 over 2015.
- 6% compound annual growth (CAGR) in proved plus probable (P+P) reserves per common share since 2013.

## LOW PRODUCTION DECLINE RATE

# 18%-20%

Bonterra's low corporate decline rate means minimal capital is required to sustain production volumes, which provides significant flexibility to increase capital for growth as commodity prices improve.

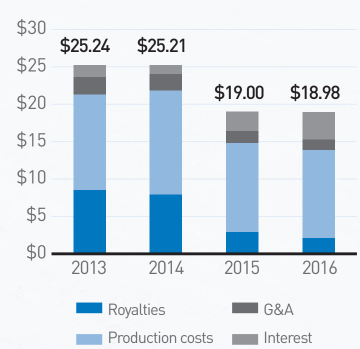
## LONG-TERM GROWTH POTENTIAL

# 20 years

With an estimated 20 years of identified economic undrilled locations in inventory, Bonterra is well positioned for ongoing value creation and long term growth potential.

## 2016 LOW ALL-IN COSTS PER BOE CONTRIBUTE TO STRONGER FUNDS FLOW

ALL-IN COSTS PER BOE




## DRILL, COMPLETE & TIE-IN COSTS

# ⬇14%

Per well capital costs were lowered in 2016 by an additional 14 percent, building on reductions achieved in 2015 of 27 percent. Bonterra improved operational efficiencies through a combination of technological advancements, pad drilling and lower service costs.

# ANNUAL HIGHLIGHTS

| As at and for the year ended ($ 000s except $ per share) | December 31, 2016 | December 31, 2015[1] | December 31, 2014 |
|---|---|---|---|
| **FINANCIAL** | | | |
| Revenue – realized oil and gas sales | 169,863 | 197,239 | 339,694 |
| Funds flow[2] | 96,305 | 117,948 | 209,665 |
| Per share – basic | 2.90 | 3.61 | 6.57 |
| Per share – diluted | 2.90 | 3.61 | 6.54 |
| Dividend payout ratio | 41% | 54% | 54% |
| Cash flow from operations | 75,294 | 107,871 | 222,353 |
| Per share – basic | 2.26 | 3.30 | 6.97 |
| Per share – diluted | 2.26 | 3.30 | 6.94 |
| Dividend payout ratio | 53% | 59% | 51% |
| Cash dividends per share | 1.20 | 1.95 | 3.54 |
| Net earnings (loss) | (24,135) | (9,080) | 38,761 |
| Per share – basic and diluted | (0.73) | (0.28) | 1.21 |
| Capital expenditures, net of dispositions | 40,797 | 58,498 | 155,565 |
| Acquisition | - | 170,430[4] | - |
| Total assets | 1,147,834 | 1,183,593 | 1,042,938 |
| Working capital deficiency | 24,921 | 29,804 | 53,642 |
| Long-term debt | 329,204 | 332,471 | 154,723 |
| Shareholders' equity | 543,824 | 595,805 | 635,198 |
| **OPERATIONS** | | | |
| Oil – bbl per day | 7,942 | 8,641 | 8,582 |
| – average price ($ per bbl) | 49.46 | 54.08 | 90.61 |
| NGLs – bbl per day | 894 | 733 | 807 |
| – average price ($ per bbl) | 19.93 | 20.80 | 52.26 |
| Natural gas – MCF per day | 22,888 | 19,694 | 22,833 |
| – average price ($ per MCF) | 2.34 | 2.94 | 4.86 |
| Total barrels of oil equivalent per day (BOE)[3] | 12,650 | 12,656 | 13,195 |

(1) Annual figures for 2015 include the results of a purchase (the Acquisition) of primarily Pembina Cardium oil and gas assets (Pembina Assets) for the period of April 15, 2015 to December 31, 2015. For the year ended December 31, 2015, production includes 260 days for the Pembina Assets and 365 days for the original Bonterra assets.

(2) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(3) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) For 2015, includes the Acquisition that closed April 15, 2015 for $170,430,000.

# QUARTERLY HIGHLIGHTS

| | 2016 | | | |
|---|---|---|---|---|
| As at and for the periods ended ($ 000s except $ per share) | Q4 | Q3 | Q2 | Q1 |
| **FINANCIAL** | | | | |
| Revenue – oil and gas sales | 48,967 | 46,236 | 41,150 | 33,510 |
| Funds flow[1] | 26,658 | 23,510 | 29,765 | 16,372 |
| Per share – basic and diluted | 0.80 | 0.71 | 0.90 | 0.49 |
| Dividend payout ratio | 37% | 42% | 33% | 61% |
| Cash flow from operations | 31,537 | 19,219 | 13,392 | 11,146 |
| Per share – basic and diluted | 0.94 | 0.58 | 0.40 | 0.34 |
| Dividend payout ratio | 32% | 52% | 75% | 89% |
| Cash dividends per share | 0.30 | 0.30 | 0.30 | 0.30 |
| Net loss | (1,168) | (5,830) | (5,582) | (11,555) |
| Per share – basic and diluted | (0.03) | (0.18) | (0.17) | (0.35) |
| Capital expenditures, net of dispositions | 12,270 | 17,424 | 9,420 | 1,683 |
| Total assets | 1,147,834 | 1,163,743 | 1,169,782 | 1,174,141 |
| Working capital deficiency | 24,921 | 26,361 | 18,429 | 13,115 |
| Long-term debt | 329,204 | 335,953 | 336,923 | 345,118 |
| Shareholders' equity | 543,824 | 549,870 | 564,075 | 575,925 |
| **OPERATIONS** | | | | |
| Oil – bbl per day | 7,467 | 8,197 | 7,780 | 8,325 |
| – average price ($ per bbl) | 58.02 | 51.80 | 51.64 | 37.33 |
| NGLs – bbl per day | 911 | 942 | 877 | 845 |
| – average price ($ per bbl) | 3.32 | 17.29 | 20.79 | 14.72 |
| Natural gas – MCF per day | 22,540 | 24,948 | 21,771 | 22,274 |
| – average price ($ per MCF) | 3.32 | 2.47 | 1.48 | 2.02 |
| Total BOE per day[2] | 12,134 | 13,298 | 12,285 | 12,882 |

(1) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(2) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## MESSAGE TO SHAREHOLDERS

BONTERRA ENERGY CORP. ("BONTERRA" OR THE "COMPANY") CONTINUED TO REALIZE OPERATIONAL AND FINANCIAL SUCCESS IN 2016 THROUGH A CHALLENGING COMMODITY PRICE ENVIRONMENT, BY SUCCESSFULLY HOLDING PRODUCTION FLAT, INCREASING RESERVES AND SPENDING 30 PERCENT LESS CAPITAL THAN IN 2015 WHILE REDUCING OVERALL DEBT. BY FOCUSING ON FACTORS THAT ARE WITHIN ITS CONTROL, THE COMPANY MAINTAINED ITS FINANCIAL FLEXIBILITY, FUTURE GROWTH OPPORTUNITIES AND LONG-TERM CORPORATE SUSTAINABILITY STRATEGY DURING A PERIOD OF RECOVERY FOR THE ENERGY SECTOR.

The Company is unique compared to other oil and gas producers with an exceptionally low decline rate of approximately 18 to 20 percent, which means less capital spending is required in order to sustain production volumes. In 2016, production was maintained at 12,650 BOE per day with only $41 million in capital spent. Additionally, the Company retains full upside to commodity price improvements which will support higher funds flows in an increasing sustainable price environment. The Company's low all-in cash costs of less than $20 per BOE further contribute to stronger funds flows, with free cash able to be directed to debt repayment, increased capital spending or dividend increases.

During 2016, Bonterra focused on several areas, including:

- **Cost Reductions:** Through disciplined execution, Bonterra successfully reduced operating costs by two percent on a per BOE basis (which was already reduced by 14 percent in 2015) and general and administrative expenses by 12 percent from the same period a year ago. The Company's all-in corporate costs were among the lowest in the sector at approximately $18.98 per BOE including royalties, operating expenses (including transportation costs), administrative expense and interest on debt.
- **Operational Efficiencies:** Bonterra realized a 14 percent further reduction in capital levels required for drilling, completions and infrastructure in 2016, building on what had been achieved in 2015. By utilizing pad drilling from sites with existing infrastructure, achieving fewer drilling days per well, better efficiencies in the field and general service cost reductions, Bonterra was able to grow reserves with attractive capital efficiencies of approximately $17,000 per BOE.
- **Managing Financial Flexibility:** Bonterra generated free cash after capital spending and dividend distributions to pay down bank debt and reduced net debt to $354 million from $362 million. The Company will continue to focus on reducing net debt to a level that is less than 2.5 times funds flow during low commodity prices and less than 1.5 times funds flow when oil prices are in excess of US $60 West Texas Intermediate (WTI) and natural gas is $3.50 Cdn per MCF for Bonterra's realized price.
- **Access to Infrastructure:** Access to consistent and reliable infrastructure to process and move volumes are critical to Bonterra's success. During 2016, the Company maintained its natural gas production firm service commitments at more than 90 percent which will reduce transportation curtailments associated with interruptible service, therefore decreasing restrictions on oil production.
- **Commodity Pricing:** Commodity prices for the year averaged approximately US $43.30 WTI for oil, AECO $2.15 per MCF for natural gas and the Cdn/US exchange rate was $0.755.
- **Future Growth Potential:** Bonterra has one of the largest inventories of economic undrilled locations amongst its peer group with an estimated 20 years of opportunities in inventory that can be targeted as commodity prices recover. Should commodity prices remain low, it is expected that fewer wells would be drilled annually, increasing Bonterra's undrilled inventory to approximately 30 years, offering substantial future growth potential.

> **The future for Bonterra remains positive over the long-term as the Company will continue to be conservatively managed to withstand a challenging commodity price environment.**

- **Conservative Business Approach:** The Company continues to be cautious and conservative regarding the determination of future reserves bookings. With approximately 33 percent of its undrilled identified well locations for the Pembina Cardium only included in the reserves evaluation, Bonterra is well positioned to capture future upside as commodity prices increase.
- **Balance Sheet Protection:** Bonterra has a history of protecting long-term shareholder returns and has proven this again in 2016. The Company continued to reduce costs and was able to generate funds flow that exceeded its capital budget and dividend payments, enhancing its financial flexibility. The Company is able to promptly respond to improvements in commodity prices by electing to increase the capital budget, pay down debt, increase dividends or some combination thereof.
- **Maximizing Asset Value:** In 2016, Bonterra expanded its waterflood program by increasing the conversion of producing wells to water injection wells, further supporting its low decline rate. The waterflood scheme is expected to improve the recovery of large oil in place in the Pembina Cardium field, which would result in greater long-term value creation for shareholders.

## OUTLOOK

Bonterra's initial capital expenditures budget for 2017 is approximately $70 million and is designed to maintain a balance between funds flow and capital spending plus dividend distributions. Annual production volumes in 2017 are estimated to increase five percent over 2016 and range between 13,000 and 13,500 BOE per day in 2017. Based on the Company's commodity price assumptions for 2017 of US $55 WTI, AECO $3.10 per MCF and foreign exchange of Cdn/US of $0.74, the Company expects to generate funds flow of approximately $145 million. Assuming dividends are approximately $40 million annually, or a stable $0.10 per share per month, and approximately $15 million from other sources, Bonterra forecasts that approximately $50 million would be available to reduce outstanding bank debt. Depending on commodity prices changes, capital spending and dividend distributions will be reviewed on a monthly basis.

The Company will continue pursuing its sustainable growth strategy by reducing the amount of debt and managing its dividend in a responsible manner. Bonterra will continue to focus on operational efficiencies, financial discipline and optimal returns for shareholders, independent of the weaker commodity prices, continued provincial and federal political uncertainty and a new US President proposing increased consumer and manufacturing protectionism including border tax discussions for imported goods, the effect of which related to oil and gas sales to the US cannot be quantified at this time.

Bonterra will continue to be one of the stronger companies in the resource industry by being a low cost producer, maintaining a low production decline rate and having a large inventory of economic undrilled locations. The future for Bonterra remains positive over the long term as the Company will continue to be conservatively managed to withstand a challenging commodity price environment.

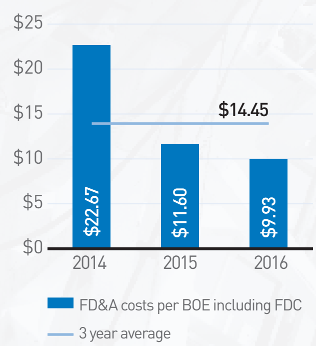
The Board of Directors wishes to thank the employees for their contribution and Bonterra's shareholders for their continued support.

**GEORGE F. FINK**
Chief Executive Officer and Chairman of the Board

# By the Numbers.

## IMPROVING FD&A COSTS

### FD&A COSTS PER BOE, INCLUDING FDC[1]

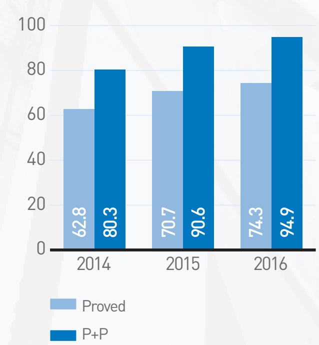



(1) Calculated on P+P reserves

Over the past three years, Bonterra has successfully reduced its Finding, Development & Acquisition ("FD&A") costs, which is a reflection of its high quality assets and operational expertise.

## STEADILY GROWING RESERVES

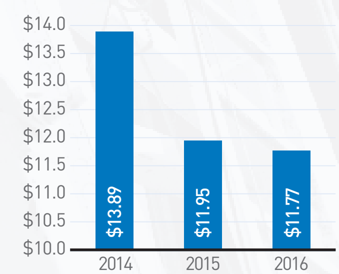
### RESERVES GROWTH (MBOE)




In 2016, Bonterra's P+P reserves grew 5% and its reserve life index was approximately 20 years.

## OPERATING EXPENSES

### OPERATING COSTS PER BOE ($ PER BOE)




Bonterra continues to reduce operating costs per BOE which contributes to stronger netbacks, particularly as commodity prices improve.

BONTERRA'S ASSETS ARE CONCENTRATED IN THE PEMBINA CARDIUM POOL IN CENTRAL ALBERTA, ONE OF CANADA'S LARGEST OIL FIELDS, CHARACTERIZED BY LOW-RISK DRILLING OPPORTUNITIES, STABLE PRODUCTION RATES AND HIGH QUALITY LIGHT OIL. AS ONE OF THE AREA'S LARGEST OPERATORS, BONTERRA HAS OVER 20 YEARS OF DRILLING OPPORTUNITIES AND IS ALWAYS SEEKING TO EXPAND ITS INVENTORY OF WELL LOCATIONS.

## EFFICIENT

Bonterra has achieved significant cost savings in driving down capital costs per well while improving recoveries through pad drilling, increased well spacing density and pioneering new technology. Advances in completion technology and horizontal, multi-well pad drilling have improved capital efficiencies. A significant portion of cost reductions are structural which means Bonterra will continue to realize savings when commodity prices improve.

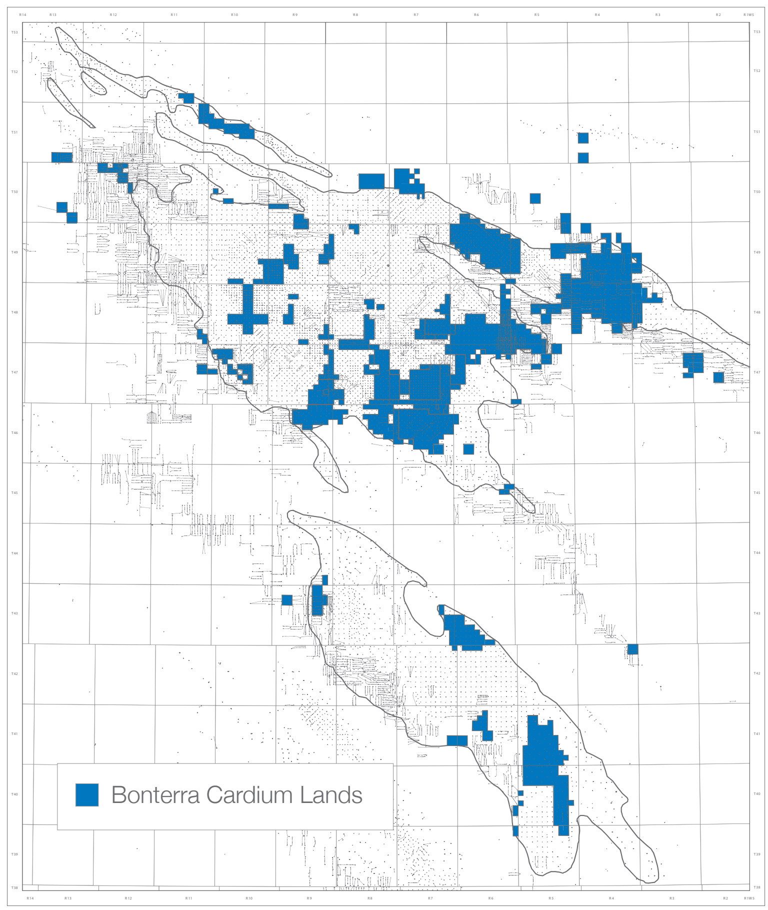
## SUSTAINABLE

Bonterra has a low production decline rate and its conservative 2016 reserves booking does not fully reflect improvements in well performance from enhanced completions. Bonterra's booked reserves currently represent only 33 percent of its internally identified inventory of future undrilled locations in the Pembina Cardium area supporting long-term sustainable growth.

## DISCIPLINED

Exercising conservative financial management and preserving balance sheet strength remain key priorities in Bonterra's disciplined approach. With ongoing instability in commodity prices, Bonterra continues to assess its results monthly and set the monthly dividend level based on the prior month's actual funds flow. This approach affords flexibility to adjust spending allocated to capital, dividends and debt reduction and enhances Bonterra's ability to deliver attractive returns to shareholders.

Bonterra is well-positioned to succeed in a low-price environment and capture future growth as the industry recovers.




**"To date, less than 14 percent of the estimated 10.6 billion barrels of oil in place have been produced which offers significant development potential."**

## SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2016

| Reserves Category | Light & Medium Crude Oil (Mbbl) | Conventional Natural Gas (MMCF) | Natural Gas Liquids (Mbbl) | Oil Equivalent[4] (MBOE) | Future Development Capital (000s) |
|---|---|---|---|---|---|
| **PROVED** | | | | | |
| Developed Producing | 25,568 | 68,940 | 2,726 | 39,784 | $ 174 |
| Developed Non-Producing | 906 | 3,058 | 105 | 1,521 | $ 1,706 |
| Undeveloped | 21,107 | 57,109 | 2,326 | 32,951 | $ 544,833 |
| **TOTAL PROVED** | 47,581 | 129,108 | 5,158 | 74,257 | $ 546,713 |
| **PROBABLE** | 12,739 | 38,162 | 1,549 | 20,648 | $ 19,528 |
| **TOTAL PROVED + PROBABLE**[1][2][3] | 60,320 | 167,269 | 6,707 | 94,905 | $ 566,241 |

(1) Reserves have been presented on gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company.

(2) Totals may not add due to rounding.

(3) Based on Sproule's December 31, 2016 escalated price deck.

(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

## RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPLE PRODUCT TYPE AS OF DECEMBER 31, 2016[1]

| | Light & Medium Crude Oil | | Conventional Natural Gas | | Natural Gas Liquids | | Total | |
|---|---|---|---|---|---|---|---|---|
| | Proved (Mbbl) | Proved + Probable (Mbbl) | Proved (MMCF) | Proved + Probable (MMCF) | Proved (Mbbl) | Proved + Probable (Mbbl) | Proved (MBOE) | Proved + Probable (MBOE) |
| Opening Balance December 31, 2015 | 47,037 | 59,558 | 111,172 | 146,128 | 5,118 | 6,708 | 70,684 | 90,621 |
| Extensions & Improved Recovery[2] | 3,363 | 4,233 | 8,447 | 10,454 | 366 | 460 | 5,138 | 6,436 |
| Technical Revisions | 1,221 | 646 | 23,892 | 21,770 | 254 | (19) | 5,457 | 4,254 |
| Discoveries | - | - | - | - | - | - | - | - |
| Acquisitions | 93 | 115 | 326 | 410 | 10 | 13 | 157 | 196 |
| Dispositions[3] | (18) | (24) | - | - | - | - | (18) | (24) |
| Economic Factors | (1,208) | (1,302) | (6,352) | (3,116) | (264) | (128) | (2,530) | (1,949) |
| Production | (2,907) | (2,907) | (8,377) | (8,377) | (327) | (327) | (4,630) | (4,630) |
| **CLOSING BALANCE, DECEMBER 31, 2016**[4] | 47,581 | 60,320 | 129,108 | 167,269 | 5,158 | 6,707 | 74,257 | 94,905 |

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) Increases to Extensions & Improved Recovery include infill drilling and are the result of step out locations drilled by Bonterra and other operators on or near Company-owned lands.

(3) Includes volumes associated with farm-outs.

(4) Totals may not add due to rounding.

## SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2016

| ($ 000s) | Net Present Value Before Income Taxes Discounted at (% per Year) | | | |
|---|---|---|---|---|
| Reserves Category | 0% | 5% | 10% | 15% |
| **PROVED** | | | | |
| Developed Producing | 1,392,381 | 945,720 | 717,404 | 581,440 |
| Developed Non-Producing | 41,473 | 30,405 | 23,239 | 18,545 |
| Undeveloped | 925,699 | 519,021 | 316,757 | 203,333 |
| **TOTAL PROVED** | 2,359,552 | 1,495,146 | 1,057,401 | 803,318 |
| **PROBABLE** | 925,389 | 478,075 | 307,422 | 223,398 |
| **TOTAL PROVED + PROBABLE**[(1)(2)(3)(4)] | 3,284,941 | 1,973,222 | 1,364,823 | 1,026,716 |

(1) Evaluated by Sproule as at December 31, 2016. Net present value of future net revenue does not represent fair value of the reserves.

(2) Net present values equals net present value before income taxes based on Sproule's forecast prices and costs as of December 31, 2016. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material.

(3) Includes abandonment and reclamation costs as defined in NI 51-101.

(4) Totals may not add due to rounding.

## FINDING, DEVELOPMENT & ACQUISITION (FD&A) AND FINDING & DEVELOPMENT (F&D) COSTS

| | Proved Reserve Net Additions | | | | P+P Reserve Net Additions | | | |
|---|---|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2014 | 3 Yr Avg[(4)] | 2016 | 2015 | 2014 | 3 Yr Avg[(4)] |
| **FD&A COSTS PER BOE**[(1)(2)(3)] | | | | | | | | |
| Including FDC | $ 10.87 | $ 11.52 | $ 18.90 | $ 14.28 | $ 9.93 | $ 11.60 | $ 22.67 | $ 14.45 |
| Excluding FDC | $ 4.91 | $ 15.50 | $ 11.57 | $ 11.41 | $ 4.58 | $ 15.29 | $ 15.54 | $ 12.56 |
| **F&D COSTS PER BOE**[(1)(2)(3)] | | | | | | | | |
| Including FDC | $ 10.89 | $ 4.76 | $ 18.89 | $ 15.07 | $ 9.91 | $ 3.12 | $ 22.71 | $ 16.04 |
| Excluding FDC | $ 4.81 | $ 33.26 | $ 11.53 | $ 10.84 | $ 4.44 | $ 56.32 | $ 15.53 | $ 12.79 |

(1) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) 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 reserve additions for that year.

(3) FD&A and F&D costs are net of proceeds of disposal and the FD&A costs per BOE are based on reserves acquired net of reserves disposed of.

(4) Three year average is calculated using three year total capital costs and reserve additions on both a Proved and Proved + Probable reserves on a weighted average basis.

## COMMODITY PRICES USED IN THE ABOVE CALCULATIONS OF RESERVES ARE AS FOLLOWS:

| | Edmonton Par Price ($Cdn per bbl) | Natural Gas AECO-C Spot ($Cdn per mmbtu) | Butanes Edmonton ($Cdn per bbl) | Pentanes Edmonton ($Cdn per bbl) | Operating Cost Inflation Rate (% per Year) | Exchange Rate ($US/$Cdn) |
|---|---|---|---|---|---|---|
| FORECAST[(1)(2)] | | | | | | |
| 2017 | 65.58 | 3.44 | 47.60 | 67.95 | 0.0 | 0.780 |
| 2018 | 74.51 | 3.27 | 55.49 | 75.61 | 2.0 | 0.820 |
| 2019 | 78.24 | 3.22 | 57.65 | 78.82 | 2.0 | 0.850 |
| 2020 | 80.64 | 3.91 | 58.80 | 80.47 | 2.0 | 0.850 |
| 2021 | 82.25 | 4.00 | 59.98 | 82.15 | 2.0 | 0.850 |
| 2022 | 83.90 | 4.10 | 61.18 | 83.86 | 2.0 | 0.850 |
| 2023 | 85.58 | 4.19 | 62.40 | 85.61 | 2.0 | 0.850 |
| 2024 | 87.29 | 4.29 | 63.50 | 87.39 | 2.0 | 0.850 |
| 2025 | 89.03 | 4.40 | 64.92 | 89.21 | 2.0 | 0.850 |
| 2026 | 90.81 | 4.50 | 66.22 | 91.07 | 2.0 | 0.850 |
| 2027 | 92.63 | 4.61 | 67.54 | 92.96 | 2.0 | 0.850 |

(1) Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.

(2) The forecasted prices were provided by the independent reserves evaluator Sproule Associates Limited.

## PRODUCTION

| | 2016 | | |
|---|---|---|---|
| | Oil & NGLs (Bbl Per Day) | Conventional Natural Gas (MCF Per Day) | Total (BOE Per Day) |
| Alberta | 8,705 | 21,825 | 12,342 |
| Saskatchewan | 123 | 56 | 132 |
| British Columbia | 8 | 1,007 | 176 |
| | 8,836 | 22,888 | 12,650 |

## LAND HOLDINGS

| | 2016 | | 2015 | |
|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres |
| Alberta | 297,388 | 180,150 | 296,684 | 179,503 |
| Saskatchewan | 8,865 | 6,193 | 8,891 | 6,200 |
| British Columbia | 62,045 | 22,638 | 62,045 | 22,639 |
| | 368,298 | 208,981 | 367,620 | 208,342 |

## PETROLEUM AND NATURAL GAS EXPENDITURES

The following table summarized petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, and exploration and development costs for the years ended December 31:

| ($ 000s) | 2016 | 2015 |
|---|---|---|
| Land | - | 479 |
| Acquisitions | - | 170,430 |
| Disposals | (54) | - |
| Exploration and development costs | 40,851 | 58,019 |
| Net petroleum and natural gas capital expenditures | 40,797 | 228,928 |

## DRILLING HISTORY

The following tables summarize Bonterra's gross and net drilling activity and success:

| | 2016 | | | | | |
|---|---|---|---|---|---|---|
| | Development | | Exploratory | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Crude oil | 23.0 | 18.8 | - | - | 23.0 | 18.8 |
| Natural gas | - | - | - | - | - | - |
| Total | 23.0 | 18.8 | - | - | 23.0 | 18.8 |
| Success rate | 100% | 100% | - | - | 100% | 100% |

| | 2015 | | | | | |
|---|---|---|---|---|---|---|
| | Development | | Exploratory | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Crude oil | 26.0 | 17.5 | - | - | 26.0 | 17.5 |
| Natural gas | - | - | - | - | - | - |
| Total | 26.0 | 17.5 | - | - | 26.0 | 17.5 |
| Success rate | 100% | 100% | - | - | 100% | 100% |

# MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated March 14, 2017 is a review of the operations and current financial position for the year ended December 31, 2016 for Bonterra Energy Corp. ("Bonterra" or "the Company") and should be read in conjunction with the audited financial statements presented under International Financial Reporting Standards (IFRS), including the notes related thereto.

## USE OF NON-IFRS FINANCIAL MEASURES

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio", "cash netback" and "net debt" to analyze operating performance, which are not standardized measures recognized under IFRS and do not have a standardized meaning prescribed by IFRS. These measures are commonly used in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies.

The Company calculates payout ratio percentage by dividing cash dividends paid to shareholders by cash flow from operating activities, both of which are measures prescribed by IFRS which appear on our statements of cash flows. We calculate cash netback by dividing various financial statement items as determined by IFRS by total production for the period on a barrel of oil equivalent basis. The Company calculates net debt as long-term debt plus working capital deficiency (current liabilities less current assets).

## FREQUENTLY RECURRING TERMS

Bonterra uses the following frequently recurring terms in this MD&A: "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States; "MSW Stream Index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada; "bbl" refers to barrel; "NGL" refers to Natural gas liquids; "MCF" refers to thousand cubic feet; "MMBTU" refers to million British Thermal Units; and "BOE" refers to barrels of oil equivalent. Disclosure provided herein in respect of a BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## NUMERICAL AMOUNTS

The reporting and the functional currency of the Company is the Canadian dollar.

## ANNUAL COMPARISIONS

| As at and for the year ended ($ 000s except $ per share) | | December 31, 2016 | December 31, 2015[1] | December 31, 2014 |
|---|---|---|---|---|
| **FINANCIAL** | | | | |
| Revenue – realized oil and gas sales | | 169,863 | 197,239 | 339,694 |
| Cash flow from operations | | 75,294 | 107,871 | 222,353 |
| Per share – basic | | 2.26 | 3.30 | 6.97 |
| Per share – diluted | | 2.26 | 3.30 | 6.94 |
| Payout ratio | | 53% | 59% | 51% |
| Cash dividends per share | | 1.20 | 1.95 | 3.54 |
| Net earnings (loss) | | (24,135) | (9,080) | 38,761 |
| Per share – basic and diluted | | (0.73) | (0.28) | 1.21 |
| Capital expenditures, net of disposition | | 40,797 | 58,498 | 155,565 |
| Acquisition | | - | 170,430[2] | - |
| Total assets | | 1,147,834 | 1,183,593 | 1,042,938 |
| Working capital deficiency | | 24,921 | 29,804 | 53,642 |
| Long-term debt | | 329,204 | 332,471 | 154,723 |
| Shareholders' equity | | 543,824 | 595,805 | 635,198 |
| **OPERATIONS** | | | | |
| Oil | – bbl per day | 7,942 | 8,641 | 8,582 |
| | – average price ($ per bbl) | 49.46 | 54.08 | 90.61 |
| NGLs | – bbl per day | 894 | 733 | 807 |
| | – average price ($ per bbl) | 19.93 | 20.80 | 52.26 |
| Natural gas | – MCF per day | 22,888 | 19,694 | 22,833 |
| | – average price ($ per MCF) | 2.34 | 2.94 | 4.86 |
| Total barrels of oil equivalent per day (BOE) | | 12,650 | 12,656 | 13,195 |

(1) Annual figures for 2015 include the results of a purchase ("the Acquisition") of primarily Pembina Cardium oil and gas assets ("Pembina Assets") for the period of April 15, 2015 to December 31, 2015. Production includes 260 days for the Pembina Assets and 365 days for the original Bonterra assets.

(2) Represents the Acquisition that closed April 15, 2015 for $170,430,000.

## QUARTERLY COMPARISONS

| | 2016 | | | |
|---|---|---|---|---|
| As at and for the periods ended ($ 000s except $ per share) | Q4 | Q3 | Q2 | Q1 |
| **FINANCIAL** | | | | |
| Revenue – oil and gas sales | 48,967 | 46,236 | 41,150 | 33,510 |
| Cash flow from operations | 31,537 | 19,219 | 13,392 | 11,146 |
| Per share – basic and diluted | 0.94 | 0.58 | 0.40 | 0.34 |
| Payout ratio | 32% | 52% | 75% | 89% |
| Cash dividends per share | 0.30 | 0.30 | 0.30 | 0.30 |
| Net loss | (1,168) | (5,830) | (5,582) | (11,555) |
| Per share – basic and diluted | (0.03) | (0.18) | (0.17) | (0.35) |
| Capital expenditures, net of dispositions | 12,270 | 17,424 | 9,420 | 1,683 |
| Total assets | 1,147,834 | 1,163,743 | 1,169,782 | 1,174,141 |
| Working capital deficiency | 24,921 | 26,361 | 18,429 | 13,115 |
| Long-term debt | 329,204 | 335,953 | 336,923 | 345,118 |
| Shareholders' equity | 543,824 | 549,870 | 564,075 | 575,925 |
| **OPERATIONS** | | | | |
| Oil (barrels per day) | 7,467 | 8,197 | 7,780 | 8,325 |
| NGLs (barrels per day) | 911 | 942 | 877 | 845 |
| Natural gas (MCF per day) | 22,540 | 24,948 | 21,771 | 22,274 |
| Total BOE per day | 12,134 | 13,298 | 12,285 | 12,882 |

| | 2015 | | | |
|---|---|---|---|---|
| As at and for the periods ended ($ 000s except $ per share) | Q4 | Q3 | Q2[1] | Q1 |
| **FINANCIAL** | | | | |
| Revenue – oil and gas sales | 44,678 | 52,160 | 57,921 | 42,480 |
| Cash flow from operations | 27,808 | 36,024 | 17,960 | 26,079 |
| Per share – basic and diluted | 0.84 | 1.09 | 0.56 | 0.81 |
| Payout ratio | 54% | 41% | 81% | 74% |
| Cash dividends per share | 0.45 | 0.45 | 0.45 | 0.60 |
| Net loss | (4,113) | (321) | (2,711) | (1,935) |
| Per share – basic and diluted | (0.13) | (0.01) | (0.08) | (0.06) |
| Capital expenditures, net of dispositions | 8,384 | 14,402 | 13,952 | 21,760 |
| Acquisition | - | - | 153,230[2] | 17,200[3] |
| Total assets | 1,183,593 | 1,200,856 | 1,225,291 | 1,072,534 |
| Working capital deficiency | 29,804 | 29,080 | 27,558 | 37,633 |
| Long-term debt | 332,471 | 335,863 | 361,430 | 207,217 |
| Shareholders' equity | 595,805 | 610,793 | 599,911 | 613,886 |
| **OPERATIONS** | | | | |
| Oil (barrels per day) | 8,424 | 9,177 | 8,823 | 8,128 |
| NGLs (barrels per day) | 710 | 753 | 677 | 791 |
| Natural gas (MCF per day) | 20,423 | 19,191 | 19,452 | 19,709 |
| Total BOE per day | 12,538 | 13,129 | 12,743 | 12,204 |

(1) Quarterly figures for Q2 2015 include the results of a purchase (the Acquisition) of primarily Pembina Cardium oil and gas assets (Pembina Assets) for the period of April 15, 2015 to December 31, 2015. Production includes 76 days for the Pembina Assets and 91 days for the original Bonterra assets.

(2) Includes $153,230,000 (less a deposit of $17,200,000) for the Acquisition that closed on April 15, 2015.

(3) Includes a deposit of $17,200,000 for the Acquisition.

## BUSINESS ENVIRONMENT AND SENSITIVITIES

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials and foreign exchange. The following table depicts selective market benchmark prices, differentials and foreign exchange rates in the last eight quarters to assist in understanding volatility in prices and foreign exchange rates that have impacted Bonterra's financial and operating performance. The increases or decreases for Bonterra's realized price for oil and natural gas for each of the eight quarters is explained in detail in the following table.

| | Q4-2016 | Q3-2016 | Q2-2016 | Q1-2016 | Q4-2015 | Q3-2015 | Q2-2015 | Q1-2015 |
|---|---|---|---|---|---|---|---|---|
| Crude oil<br>WTI (US$/bbl) | 49.29 | 44.94 | 45.59 | 33.45 | 42.18 | 46.43 | 57.94 | 48.63 |
| WTI to MSW Stream Index<br>Differential (US$/bbl)[1] | (3.09) | (3.02) | (3.14) | (3.78) | (2.51) | (3.45) | (2.93) | (6.93) |
| Foreign exchange<br>US$ to Cdn$ | 1.3339 | 1.3051 | 1.2886 | 1.3748 | 1.3353 | 1.3094 | 1.2294 | 1.2411 |
| Bonterra average realized<br>oil price (Cdn$/bbl) | 58.02 | 51.80 | 51.64 | 37.33 | 49.50 | 53.26 | 64.27 | 48.70 |
| Natural gas<br>AECO (Cdn$/MCF) | 3.08 | 2.31 | 1.39 | 1.82 | 2.45 | 2.89 | 2.64 | 2.74 |
| Bonterra average realized<br>gas price (Cdn$/MCF) | 3.32 | 2.47 | 1.48 | 2.02 | 2.61 | 3.36 | 2.83 | 2.97 |

(1) This differential accounts for the major difference between WTI and Bonterra's average realized price (before quality adjustments and foreign exchange).

The overall volatility in Bonterra's average realized commodity pricing can be impacted by numerous events, including but not limited to:

- Worldwide crude oil supply and demand imbalance;
- Geo-political events that affect worldwide crude oil supply and demand;
- The value of the Canadian dollar compared to the US dollar;
- The availability of take-away capacity to transport energy commodities;
- Weather dependence; and
- Timing of plant and refinery turnarounds.

Global supply and demand imbalances have placed continued pressure on oil, natural gas and liquids pricing throughout 2015 and 2016, leaving commodity prices to remain volatile. WTI benchmark pricing increased from the low of $30.62 US per bbl in February of 2016 to over $50.00 US per bbl in December 2016. The price increase can be mainly attributed to OPEC production curtailments. This reduction in global oil supply could be negated from increased USA shale production and from OPEC countries whose production has not been restricted. In future years take-away capacity will increase if Trans Mountain and Line 3 pipelines are constructed. In addition, the recent approvals to complete the Keystone XL and Dakota Access pipeline projects in the USA should also decrease production restrictions on Canadian oil and gas producers. The AECO benchmark price improved in the third and fourth quarters of 2016 compared to the multi-year low experienced in the second quarter. The increase in the AECO benchmark price is a result of a reduction in supply due to decreased drilling activity and increased demand from warm weather in the summer months. Continuing changes in production, inventories and global supply make it difficult to predict future commodity pricing with any certainty.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant.

**ANNUALIZED SENSITIVITY ANALYSIS ON CASH FLOW, AS ESTIMATED FOR 2017[1]**

| Impact on cash flow | Change ($) | $ 000s | $ per share[2] |
|---|---|---|---|
| Realized crude oil price ($/bbl) | 1.00 | 2,887 | 0.09 |
| Realized natural gas price ($/MCF) | 0.10 | 841 | 0.02 |
| $US to $Cdn exchange rate | 0.01 | 1,444 | 0.04 |

(1) This analysis uses current royalty rates, annualized estimated average production of 13,250 BOE per day and no changes in working capital.

(2) Based on annualized basic weighted average shares outstanding of 33,302,435.

## BUSINESS OVERVIEW, STRATEGY AND KEY PERFORMANCE DRIVERS

Bonterra is an upstream oil and gas company that is primarily focused on the development of its Cardium land within the Pembina and Willesden Green areas located in central Alberta. The Pembina Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original oil in place with very low recoveries. Horizontal drilling with multi stage fracing drastically improves recoveries from areas developed with vertical drilling and extends the economic edge of the reservoir where vertical drilling is not economic. Bonterra operates 88.5 percent of its production with an average working interest of 76 percent. At December 31, 2016, Bonterra has identified horizontal drilling inventory of 756 net Cardium locations. Bonterra has also identified additional drilling locations in other formations within Alberta, Saskatchewan and British Columbia.

With continued depressed commodity prices, the Company has been able to generate positive cash flow on an annual basis. Bonterra was able to reduce capital costs by 14 percent on a per well basis, production costs by two percent on a per BOE basis (which was already reduced by 14 percent in 2015) and general and administrative costs by 12 percent from the same period a year ago. In 2016, Bonterra maintained its production level with its low annual decline rate between 18 to 20 percent and with minimal capital expenditures. The Company was able to generate free cash flow, excluding non-cash working capital, in excess of its modest capital program of $41 million while maintaining its monthly dividend of $0.10 per share. Should commodity prices improve further, the Company has flexibility to reduce debt and increase capital expenditures.

During 2016, Bonterra spent approximately $41 million on its capital program on the drilling of 21 gross (18.7 net) operated wells and completing and tying-in 24 gross (21.5 net) wells (of which six wells were drilled in 2015, but not completed until 2016). Of the 21 operated wells drilled three (1.7 net) were completed and tied-in in the first quarter of 2017. As well, two (0.1 net) non-operated wells were drilled and placed on production during 2016. The Company also added pipeline and other infrastructure to redirect gas production and maintenance upgrades to reduce downtime at one of its operated gas plants in the Pembina Area. In December 2016, the Company set its capital expenditure budget for 2017 at approximately $70 million, subject to changing commodity prices.

The Company averaged 12,650 BOE per day for the 2016 year, above the annual guidance of 12,500 BOE per day. During 2016, the Company reactivated its voluntary shut-in production due to low commodity prices received in the first quarter of 2016. Voluntary shut-in production and deferral of maintenance programs due to low commodity prices accounted for 268 BOE per day over the 2016 year. Another 130 BOE day was shut-in during the year due to facility turnarounds, oil apportionments and gas capacity restrictions. Also during the fourth quarter the Company accumulated 100 bbls per day of oil inventory due to the operators of transport pipelines limiting producers to daily nominated volumes.

The Company uses over 20,000 MCF per day of natural gas firm service delivery with Transcanada Pipeline. Considering approximately 90 percent of Bonterra's current natural gas production is from solution gas, this will reduce transportation curtailments associated with interruptible service, therefore decreasing restrictions on oil production. The Company is estimating that its average annual production for 2017 will average between 13,000 BOE per day and 13,500 BOE per day, which may be adjusted subject to changing commodity prices.

On October 26, 2016, following the semi-annual review of its credit facilities, the Company's borrowing base was successfully renewed at $380 million. These credit facilities are comprised of a $330 million syndicated revolving credit facility, and a $50 million non-syndicated revolving credit facility. The revolving period on the facilities expires on April 30, 2017, with a maturity date of April 30, 2018, subject to an annual review. As at December 31, 2016, Bonterra had $329 million drawn on the $380 million credit facilities, down from $345 million as at March 31, 2016. These credit facilities provide the Company with sufficient liquidity and financial flexibility to execute its business plan. Bonterra intends to continue repaying debt through 2017.

Bonterra's successful operations are dependent upon several factors, including but not limited to, commodity prices, efficiently managing capital spending and monthly dividends, its ability to maintain desired levels of production, control over its infrastructure, its efficiency in developing and operating properties and its ability to control costs. The Company's key measures of performance with respect to these drivers include, but are not limited to: average production per day, average realized prices, and average operating costs per unit of production. Disclosure of these key performance measures can be found in the MD&A and/or previous interim or annual MD&A disclosures.

## DRILLING

| | Three months ended | | | | | | Year ended | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | December 31, 2016 | | September 30, 2016 | | December 31, 2015 | | December 31, 2016 | | December 31, 2015 | |
| | Gross[1] | Net[2] | Gross[1] | Net[2] | Gross[1] | Net[2] | Gross[1] | Net[2] | Gross[1] | Net[2] |
| Crude oil horizontal – operated | 4 | 2.7 | 11 | 10.7 | 3 | 1.5 | 21 | 18.7 | 20 | 16.7 |
| Crude oil horizontal – non-operated | 2 | 0.1 | - | - | 3 | 0.4 | 2 | 0.1 | 6 | 0.8 |
| Total | 6 | 2.8 | 11 | 10.7 | 6 | 1.9 | 23 | 18.8 | 26 | 17.5 |
| Success rate | | 100% | | 100% | | 100% | | 100% | | 100% |

(1) "Gross" wells means the number of wells in which Bonterra has a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Bonterra's percentage of working interest.

During the first quarter of 2016, the Company placed six gross (4.5 net) wells on production that were drilled and completed in the later part of 2015. In addition, the Company drilled 21 gross (18.7 net) wells, of which 18 were put on production during the year. The remaining three wells are anticipated to be on production early in the 2017 fiscal year. As well, two (0.1 net) non-operated wells were drilled and placed on production during 2016.

## PRODUCTION

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Crude oil (barrels per day) | 7,467 | 8,197 | 8,424 | 7,942 | 8,641 |
| NGLs (barrels per day) | 911 | 942 | 710 | 894 | 733 |
| Natural gas (MCF per day) | 22,540 | 24,948 | 20,423 | 22,888 | 19,694 |
| Average BOE per day | 12,134 | 13,298 | 12,538 | 12,650 | 12,656 |

Annual production volumes exceeded annual guidance and were virtually identical to the previous year. To reduce debt levels Bonterra reduced its capital program in 2016 compared to 2015 to an amount that would maintain, but not grow production volumes. Also the Company, voluntarily shut-in or deferred well maintenance programs on low netback production until the second half of 2016 when commodity prices increased, which resulted in an annual 268 BOE per day reduction in production. Bonterra also experienced unplanned pipeline restrictions that caused production to be shut-in or oil to accumulate in field storage which further reduced annual production volumes by 155 BOE per day. These production issues along with natural production declines were partially offset by a full year of production from certain oil and gas assets in the Pembina area of Alberta (the Pembina Assets) that were acquired during the second quarter in 2015, of 1,500 BOE per day.

Production for the fourth quarter was negatively affected compared to the third quarter by production curtailments primarily from pipeline restrictions and freeze offs causing 380 BOEs per day to be shut-in. This was partially offset by placing 10 new wells on production in the fourth quarter versus placing six wells on production in the third quarter of 2016.

## CASH NETBACK

The following table illustrates the calculation of the Company's cash netback from operations for the periods ended:

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| $ per BOE | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Production volumes (BOE) | 1,116,357 | 1,223,384 | 1,153,476 | 4,629,972 | 4,619,277 |
| Gross production revenue | $ 43.86 | $ 37.79 | $ 38.73 | $ 36.69 | $ 42.70 |
| Royalties | (2.76) | (2.60) | (2.55) | (2.11) | (2.89) |
| Production costs | (12.12) | (12.43) | (11.81) | (11.77) | (11.95) |
| Field netback | $ 28.98 | $ 22.76 | $ 24.37 | $ 22.81 | $ 27.86 |
| General and administrative | (1.18) | (1.11) | (1.63) | (1.37) | (1.56) |
| Interest and other | (3.92) | (3.82) | (2.98) | (3.73) | (2.60) |
| Cash netback | $ 23.88 | $ 17.83 | $ 19.76 | $ 17.71 | $ 23.70 |

Cash netbacks have decreased in 2016 compared to 2015 primarily due to lower commodity prices, along with an increase in interest expense due to increased debt from funding the Pembina Assets acquisition in April 2015. These decreases were partially offset by lower royalties and production and general and administrative costs. All-in costs (royalties, production, general and administrative and interest, and other) remain below $20 per BOE for both 2015 and 2016. The increase in quarter over quarter cash netbacks was primarily a result of an increase in commodity prices and a decrease in production costs.

## OIL AND GAS SALES

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Revenue – oil and gas sales ($ 000s) | 48,967 | 46,236 | 44,678 | 169,863 | 197,239 |
| Average Realized Prices: | | | | | |
| Crude oil ($ per barrel) | 58.02 | 51.80 | 49.50 | 49.46 | 54.08 |
| NGLs ($ per barrel) | 26.64 | 17.29 | 21.49 | 19.93 | 20.80 |
| Natural gas ($ per MCF) | 3.32 | 2.47 | 2.61 | 2.34 | 2.94 |
| Average ($ per BOE) | 43.86 | 37.79 | 38.73 | 36.69 | 42.70 |

Revenue from oil and gas sales decreased by $27,376,000 in 2016, or 14 percent, compared to 2015. This decrease was primarily due to lower commodity prices on a per BOE basis compared to the prior year. The quarter over quarter increase in oil and gas sales of $2,731,000 was a result of a 16 percent increase in commodity prices on a per BOE basis, and was partially offset by a seven percent decrease in production volumes.

The Company's product split on a revenue basis for 2016 is approximately 88 percent weighted towards crude oil and NGLs.

## ROYALTIES

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Crown royalties | 1,951 | 2,219 | 1,901 | 5,917 | 8,007 |
| Freehold, gross overriding and other royalties | 1,126 | 959 | 1,039 | 3,864 | 5,354 |
| Total royalties | 3,077 | 3,178 | 2,940 | 9,781 | 13,361 |
| Crown royalties – percentage of revenue | 4.0 | 4.8 | 4.3 | 3.5 | 4.1 |
| Freehold, gross overriding and other royalties – percentage of revenue | 2.3 | 2.1 | 2.3 | 2.3 | 2.7 |
| Royalties – percentage of revenue | 6.3 | 6.9 | 6.6 | 5.8 | 6.8 |
| Royalties $ per BOE | 2.76 | 2.60 | 2.55 | 2.11 | 2.89 |

Royalties paid by the Company consist of crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia and non-crown royalties. Total royalties on a per BOE basis decreased by $0.78 per BOE or 27 percent for 2016 compared to 2015, primarily due to lower commodity prices. Quarter over quarter royalties on a per BOE basis increased primarily due to an increase in commodity prices.

In 2016, the provincial government of Alberta announced the key highlights of the Modernized Royalty Framework ("MRF") that came into effect on January 1, 2017. These highlights include the replacement of royalty credits and holidays on conventional wells through a Drilling and Completion Cost Allowance to emulate a revenue minus cost framework, a post-payout royalty rate based on commodity prices, and the reduction of royalty rates for mature wells, with the intent of delivering a neutral internal rate of return for any given type of well compared to the previous royalty framework. No changes will be made to the royalty structure of wells drilled prior to January 2017 for a 10 year period from the royalty program's implementation date unless a producer applies to opt in to the MRF for wells that otherwise would have not been drilled. Details of the MRF calibration formulas have been released and more specific information can be found on the provincial government's website. Based on currently expected commodity price ranges, the Company anticipates that the MRF will not have a material impact on Bonterra's results of operations on a go forward basis.

## PRODUCTION COSTS

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s except $ per BOE) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Production costs | 13,536 | 15,205 | 13,622 | 54,503 | 55,215 |
| $ per BOE | 12.12 | 12.43 | 11.81 | 11.77 | 11.95 |

Production costs on a per BOE basis for 2016 decreased two percent compared to 2015. The decrease in production costs on a BOE basis was due to field optimizations and reduced chemical costs, prior period processing charge recoveries from partners, and lower freehold mineral taxes due to lower commodity prices.

Quarter over quarter, production costs on a per BOE basis decreased primarily due to reduced reactivation costs for shut-in production and repairing down wells, as the Company temporarily used six service rigs in the third quarter, compared to two service rigs in the fourth quarter. In Q3 2016 the Company also experienced an increase in road and lease maintenance costs from repairing damage caused by flooding in the Pembina area. The Company will continue to manage its well workover and facility maintenance programs to maximize cash netbacks and increase cash flow.

## OTHER INCOME

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Investment income | 10 | 2 | 41 | 18 | 251 |
| Administrative income | 70 | 46 | 15 | 214 | 77 |
| Gain on sale of equipment | 1 | - | - | 1 | - |
| | 81 | 48 | 56 | 233 | 328 |

The market value of the investments held by the Company at December 31, 2016 is $1,621,000 (December 31, 2015 – $9,538,000). The carrying value decreased primarily due to the sale of investments for proceeds of $10,783,000 during the year. The disposition resulted in a gain on sale of $3,047,000 (December 31, 2015 – $1,191,000) which was recorded as an equity transfer between accumulated other comprehensive income and retained earnings.

The Company receives administrative income for various oil and gas administrative services or production equipment rentals.

## GENERAL AND ADMINISTRATION (G&A) EXPENSE

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s except $ per BOE) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Employee compensation expense | 894 | 914 | 1,211 | 3,755 | 3,905 |
| Office and administrative expense | 421 | 448 | 666 | 2,584 | 3,302 |
| Total G&A expense | 1,315 | 1,362 | 1,877 | 6,339 | 7,207 |
| $ per BOE | 1.18 | 1.11 | 1.63 | 1.37 | 1.56 |

The decrease of $150,000 in employee compensation expense for the 2016 year compared to the same period in 2015 is due to reduced compensation paid on a per employee basis. The Company has a bonus plan in which the bonus pool consists of a range between 2.5 percent to 3.5 percent of earnings before income taxes. The Company firmly believes that tying employee compensation (including the use of stock options) to the performance of the Company clearly aligns the interests of the employees with those of shareholders.

Office and administration expense for 2016 decreased compared to the same period in 2015 due to a decrease in consulting fees, continuous disclosure fees and a decrease in the allowance for doubtful accounts.

## FINANCE COSTS

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s except $ per BOE) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Interest on long-term debt | 4,240 | 4,519 | 3,244 | 16,708 | 10,390 |
| Other interest | 219 | 205 | 252 | 789 | 1,931 |
| Interest expense | 4,459 | 4,724 | 3,496 | 17,497 | 12,321 |
| $ per BOE | 3.99 | 3.86 | 3.03 | 3.78 | 2.67 |
| Unwinding of the discounted value of decommissioning liabilities | 659 | 593 | 514 | 2,507 | 1,878 |
| Total finance costs | 5,118 | 5,317 | 4,010 | 20,004 | 14,199 |

Interest on long-term debt increased $6,318,000 in 2016 compared to 2015 as the Company increased the outstanding bank debt by $170,000,000 to finance the Pembina Asset acquisition in the second quarter of 2015. The Company's bank interest rate increased in the second half of 2015 due to a higher net debt to cash flow ratio. Interest rates are determined quarterly by the ratio of total debt (excluding accounts payable and accrued liabilities) to current quarter EBITDA (defined as net income excluding finance costs, provision for current and deferred taxes, depletion and depreciation, share-option compensation, gain or loss on sale of assets and impairment of assets) multiplied by four.

Other interest relates to amounts paid to a related party (see related party transactions) and a $12,500,000 subordinated promissory note from a private investor. For more information about the subordinated promissory note, refer to Note 12 of the December 31, 2016 annual audited financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,491,000.

## SHARE-OPTION COMPENSATION

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Share-option compensation | 1,756 | 1,558 | 1,550 | 5,818 | 4,270 |

Share-option compensation is a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

Share-option compensation increased by $1,548,000 from the same period a year ago due to 902,000 share-options issued in the third quarter of 2016.

Based on the outstanding options as of December 31, 2016, the Company has an unamortized expense of $3,622,000, of which $3,606,000 will be recorded for 2017 and $16,000 thereafter. For more information about options issued and outstanding, refer to Note 16 of the December 31, 2016 audited annual financial statements.

## DEPLETION AND DEPRECIATION, EXPLORATION AND EVALUATION (E&E) AND GOODWILL

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Depletion and depreciation | 22,818 | 27,064 | 25,775 | 100,992 | 101,150 |
| Impairment of oil and gas assets | 2,505 | - | - | 2,505 | - |
| Exploration and evaluation | - | - | 183 | - | 183 |

Provision for depletion and depreciation decreased by $158,000 for 2016 compared to the same period in 2015. The slight decrease in depletion and depreciation is primarily due to comparable production levels, an increase in the estimate for decommissioning liabilities offset by reduced capital spending. The increase in decommissioning liabilities was due to estimated inflation rising by 0.5 percent and estimate updates for the various facilities and infrastructure in which the Company has ownership.

The exploration and evaluation expense relates to expired leases.

On December 31, 2016, the Company recorded a $799,000 impairment charge to E&E expenditures and $1,706,000 to Property, Plant and Equipment (PPE) for a total impairment charge of $2,505,000 all related to its non-core British Columbia gas properties. The impairment recorded on the British Columbia properties relates to reduced forecasted gas prices and increased future estimated operating costs by 11 percent in Q4 2016. There was no impairment provision recorded for the year ended December 31, 2015.

## TAXES

The Company recorded a total tax recovery of $5,711,000 (2015 – total tax expense of $12,172,000). The increase in the total tax recovery is due to an increase in loss before income taxes. Included in the total tax recovery is a current tax estimate of $3,547,000 for provincial income tax losses that were carried back to recover prior provincial income taxes paid. The Company has received payment of $1,771,000 and has a current receivable of $1,776,000. The receivable is expected to be collected in the second quarter of 2017.

For additional information regarding income taxes, see Note 15 of the December 31, 2016 annual audited financial statements.

## NET LOSS

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s except $ per share) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Net Loss | (1,168) | (5,830) | (4,113) | (24,135) | (9,080) |
| $ per share – basic | (0.03) | (0.18) | (0.13) | (0.73) | (0.28) |
| $ per share – diluted | (0.03) | (0.18) | (0.13) | (0.73) | (0.28) |

Net loss for the 2016 year increased by $15,055,000 compared to 2015. The increase in net loss was a result of lower commodity prices, increased finance costs and an impairment charge on its non-core British Columbia properties, partially offset by a decrease in royalties, production costs and a current and deferred income tax recovery.

The quarter over quarter decrease in net loss was mainly due to increased commodity prices, decrease in depletion and depreciation and production costs and was partially offset by the impairment charge in the fourth quarter, reduced production volumes and a lower deferred income tax recovery.

## OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income for 2016 consists of an unrealized gain before tax on investments (including investment in a related party) of $2,866,000 relating to an increase in the investments' fair value (December 31, 2015 – unrealized loss of $2,519,000). Realized gains decrease accumulated other comprehensive income as these gains are transferred to retained earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments including the investment in a related party, net of tax.

## CASH FLOW FROM OPERATIONS

| | Three months ended | | | Year ended | |
|---|---|---|---|---|---|
| ($ 000s except $ per share) | December 31, 2016 | September 30, 2016 | December 31, 2015 | December 31, 2016 | December 31, 2015 |
| Cash flow from operations | 31,537 | 19,219 | 27,808 | 75,294 | 107,871 |
| $ per share – basic | 0.94 | 0.58 | 0.84 | 2.26 | 3.30 |
| $ per share – diluted | 0.94 | 0.58 | 0.84 | 2.26 | 3.30 |

In 2016, cash flow from operations decreased by $32,577,000 compared to 2015. This was primarily due to a decrease in revenue from oil and gas sales, an increase in asset retirement obligations settled and higher finance costs, partially offset by a decrease in royalties, production costs and a current income tax recovery. The quarter over quarter increase in cash flow of $12,318,000 is primarily due to an increase in commodity prices, non-cash working capital and a decrease in production costs. The Company has been able to reduce long-term debt and its subordinated promissory note by $18,414,000 over the last three quarters, while funding its capital program and maintaining dividends to shareholders.

## RELATED PARTY TRANSACTIONS

Bonterra holds 1,034,523 (December 31, 2015 – 1,034,523) common shares in Pine Cliff Energy Ltd. ("Pine Cliff") which represents less than one percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares had a fair market value as of December 31, 2016 of $1,169,000 (December 31, 2015 of $962,000). Pine Cliff paid a management fee to the Company of $15,000 (December 31, 2015 – $60,000) plus the reimbursement of certain administrative expenses. Services provided by the Company include executive services, oil and gas administration and office administration. All services performed are charged at estimated fair value. On April 1, 2016, the management agreement was terminated. As at December 31, 2016, the Company had an account receivable from Pine Cliff of $51,000 (December 31, 2015 – $293,000).

As at December 31, 2016, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2015 – $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan for 2016 was $249,000 (December 31, 2015 – $261,000). This loan results in a substantial benefit to Bonterra as the interest paid to the CEO by Bonterra is lower than bank interest.

## LIQUIDITY AND CAPITAL RESOURCES

### Net Debt to Cash Flow from Operations

Bonterra continues to focus on monitoring and managing its cash flow, capital expenditures and dividend payments. The Company's net debt to a 12 month trailing cash flow ratio as of December 31, 2016 was a ratio of 4.7 to 1 times. The increase in net debt to cash flow is mainly due to the Pembina Asset acquisition on April 15, 2015 and low commodity prices realized in 2015 and 2016. To manage its bank debt Bonterra significantly reduced planned capital expenditures during this low commodity price environment and reduced the monthly dividend payments from $0.15 to $0.10 per common share starting with the January 2016 dividend. With the current commodity price environment the Company will continue to assess its monthly dividend and capital expenditures on a month to month basis.

### Working Capital Deficiency and Net Debt

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Working capital deficiency | 24,921 | 29,807 |
| Long-term bank debt | 329,204 | 332,471 |
| Net Debt | 354,125 | 362,278 |

The Company has sufficient availability on its credit facility to repay both the related party loan and the subordinated promissory note if required. The Company manages net debt during each quarter by monitoring capital spending and dividends paid compared to cash flow from operations.

Net debt is a combination of long-term bank debt and working capital. Net debt for December 2016 decreased by $8,153,000 from December 2015. Lower commodity prices were offset by decreased capital spending, proceeds from liquidating a portion of the marketable securities the Company held, production cost control and a reduction of the monthly dividend from $0.15 per share to $0.10 per share commencing with the January 2016 dividend. In 2016 the Company repaid $12,500,000 of its subordinated promissory note, which decreased working capital deficiency but increased long-term debt. Long-term debt was initially reduced by the disposition of a portion of the marketable securities for proceeds of $10,783,000.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and sale of non-core assets and investments. Included in the working capital deficiency at December 31, 2016 is $24.5 million of debt relating to the subordinated promissory note and the amount due to a related party.

The Company has not currently entered into any financial derivative contracts.

## Capital Expenditures

During the year ended December 31, 2016, the Company incurred capital expenditures of $40,851,000 (December 31, 2015 – $58,498,000). The costs relate to the drilling of 21 gross (18.7 net) Cardium operated horizontal wells and related infrastructure costs, of which 18 were completed, equipped and tied-in. The Company also incurred equipment and tie-in costs related to six gross (4.5 net) Cardium operated wells that were drilled and completed in 2015. As well, two (0.1 net) non-operated wells were drilled and placed on production during 2016.

## Liability Management Ratio ("LMR") Update

On June 20, 2016, the Alberta Energy Regulator increased the LMR threshold for license transfers to 2.0. At the time, Bonterra's LMR of assets versus liabilities, as determined by the formula set out in the program, was 1.74. The Company reacted immediately to the regulatory changes and without spending any money, began an internal program that successfully brought the LMR to over 2.0.

The Company currently has an LMR rating of 2.03 and does not expect that with its current LMR there will be any impediments to future acquisition opportunities.

## Long-term Debt

Long-term debt represents the outstanding draws from the Company's credit facilities as described in the notes to the Company's condensed financial statements. As of December 31, 2016, the Company has bank facilities consisting of a $330,000,000 (December 31, 2015 – $375,000,000) syndicated revolving credit facility and a $50,000,000 (December 31, 2015 – $50,000,000) non-syndicated revolving credit facility, for total credit facilities of $380,000,000. Amounts drawn under these credit facilities at December 31, 2016 totaled $329,204,000 (December 31, 2015 – $332,471,000). The interest rates for the year ended December 31, 2016 on the Company's Canadian prime rate loan and Banker's Acceptances averaged between five to six percent. The loan is revolving to April 30, 2017 with a maturity date of April 30, 2018, subject to annual review. The credit facilities have no fixed terms of repayment.

Advances drawn under the credit facilities are secured by a fixed and floating charge debenture over the assets of the Company. In the event the credit facilities are not extended or renewed, amounts drawn under the facility would be due and payable on the maturity date. The size of the committed credit facilities is based primarily on the value of the Company's producing petroleum and natural gas assets and related tangible assets as determined by the lenders. For more information see Note 13 of the December 31, 2016 annual audited financial statements.

## Shareholders' Equity

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,330,244 (December 31, 2015 – 3,314,344) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years. For additional information regarding options outstanding, see Note 16 of the December 31, 2016 audited annual financial statements.

| | December 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| Issued and fully paid – common shares | Number | Amount ($ 000s) | Number | Amount ($ 000s) |
| Balance, beginning of year | 33,143,435 | 760,020 | 32,169,623 | 728,934 |
| Share issuances, private placement | - | - | 973,812 | 31,162 |
| Share issue costs, net of tax | | - | | (76) |
| Issued pursuant to the Company's share option plan | 159,000 | 3,253 | - | - |
| Transfer from contributed surplus to share capital | | 515 | | - |
| Balance, end of year | 33,302,435 | 763,788 | 33,143,435 | 760,020 |

### Commitments

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to eight years. The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 6.9 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum payments for the firm service gas transportation agreements using current tariff rates and the non-cancellable building and office equipment leases as at December 31, 2016 are as follows;

| ($ 000s) | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Firm service commitments | 1,384 | 1,396 | 1,373 | 1,268 | 1,168 | 2,881 | 9,470 |
| Office lease commitments | 522 | 503 | 506 | 535 | 535 | 1,073 | 3,674 |
| Total | 1,906 | 1,899 | 1,879 | 1,803 | 1,703 | 3,954 | 13,144 |

## DIVIDEND POLICY

For the year ended December 31, 2016, the Company declared and paid dividends of $39,807,000 ($1.20 per share) (December 31, 2015 – $63,607,000 ($1.95 per share)). Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, cash flow from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide its shareholders a combination of sustainable growth and meaningful dividend income.

Bonterra's dividends to its shareholders are funded by cash flow from operating activities with the remaining cash flow directed towards capital spending and the repayment of debt. To the extent that the excess cash flow from operations after dividends is not sufficient to cover capital spending, the shortfall is funded by funds from the exercising of employee stock options, the sale of investments and by drawdowns from Bonterra's credit facilities. Bonterra intends to provide dividends to shareholders that are sustainable to the Company considering its liquidity and its long-term operational strategy. In addition, since the level of dividends is highly dependent upon cash flow generated from operations, which fluctuates significantly in relation to changes in financial and operational performance, commodity prices, interest and exchange rates and many other factors, future dividends cannot be assured. Bonterra's payout ratio based on cash flow from operations was 54 percent for the year ended December 31, 2016 (59 percent for the year ended December 31, 2015).

## QUARTERLY FINANCIAL INFORMATION

| | 2016 | | | |
|---|---|---|---|---|
| For the periods ended ($ 000s except $ per share) | Q4 | Q3 | Q2 | Q1 |
| Revenue – oil and gas sales | 48,967 | 46,236 | 41,150 | 33,510 |
| Cash flow from operations | 31,537 | 19,219 | 13,392 | 11,146 |
| Net loss | (1,168) | (5,830) | (5,582) | (11,555) |
| Per share – basic | (0.03) | (0.18) | (0.17) | (0.35) |
| Per share – diluted | (0.03) | (0.18) | (0.17) | (0.35) |

| | 2015 | | | |
|---|---|---|---|---|
| For the periods ended ($ 000s except $ per share) | Q4 | Q3 | Q2 | Q1 |
| Revenue – oil and gas sales | 44,678 | 52,160 | 57,921 | 42,480 |
| Cash flow from operations | 27,808 | 36,024 | 17,960 | 26,079 |
| Net earnings (loss) | (4,113) | (321) | (2,711) | (1,935) |
| Per share – basic | (0.13) | (0.01) | (0.08) | (0.06) |
| Per share – diluted | (0.13) | (0.01) | (0.08) | (0.06) |

The fluctuations in the Company's revenue and net earnings from quarter to quarter are caused by variations in production volumes, realized commodity pricing and the related impact on royalties and production costs. In the first and second quarters of 2016, net earnings and cash flow are lower than other periods due to a significant decrease in commodity prices.

## CRITICAL ACCOUNTING ESTIMATES

There have been no changes to the Company's critical accounting policies and estimates as of the period ended in the financial statements.

## FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

### Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim fillings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief financial Officer of Bonterra evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Bonterra's DC&P were effective at December 31, 2016.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;
2. Are designed to 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 Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and
3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The CEO and CFO have designed, or caused to be designed under their supervision, ICFR as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013).

The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial period end of the Company and concluded that such internal controls over financial reporting are effective.

It should be noted that while Bonterra's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and are effective; they do not expect that these controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that its objectives are met.

## FUTURE ACCOUNTING PRONOUNCEMENTS

In May 2014, the International Accounting Standards Board (IASB) issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. This standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has not yet assessed the impact, if any, that the new standard will have on its financial statements or whether to early adopt this new requirement.

In January 2016, the IASB issued IFRS 16 "Leases," which replaces IAS 17 "Leases." For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers." The standard is required to be adopted either retrospectively or using a modified retrospective approach. The Company has not yet assessed the impact, if any, that the new amended standard will have on its financial statements or whether to early adopt this new requirement.

Additional information relating to the Company may be found on www.sedar.com or visit our website at www.bonterraenergy.com.

# MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. The timely preparation of the financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

**GEORGE F. FINK**
Chief Executive Officer and
Chairman of the Board

March 14, 2017

**ROBB D. THOMPSON**
Chief Financial Officer

March 14, 2017

# INDEPENDENT AUDITOR'S REPORT

## TO THE SHAREHOLDERS OF BONTERRA ENERGY CORP.

We have audited the accompanying financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statement of financial position as at December 31, 2016 and 2015, and the statement of comprehensive loss, statement of cash flow and statement of changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Financial Statements

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

### Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

### Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Bonterra Energy Corp. as at December 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

**CHARTERED PROFESSIONAL ACCOUNTANTS**

March 14, 2017

Calgary, Canada

# STATEMENT OF FINANCIAL POSITION

| As at ($ 000s) | Note | December 31, 2016 | December 31, 2015 |
|---|---|---|---|
| **ASSETS** | | | |
| **CURRENT** | | | |
| Accounts receivable | | 20,774 | 15,433 |
| Crude oil inventory | | 1,060 | 868 |
| Prepaid expenses | | 2,529 | 2,798 |
| Investments | | 452 | 8,576 |
| | | 24,815 | 27,675 |
| Investment in related party | 6 | 1,169 | 962 |
| Exploration and evaluation assets | 7 | 7,073 | 7,925 |
| Property, plant and equipment | 8 | 1,013,133 | 1,045,387 |
| Investment tax credit receivable | 15 | 8,834 | 8,834 |
| Goodwill | 9 | 92,810 | 92,810 |
| | | 1,147,834 | 1,183,593 |
| **LIABILITIES** | | | |
| **CURRENT** | | | |
| Accounts payable and accrued liabilities | 10 | 25,236 | 20,479 |
| Due to related party | 11 | 12,000 | 12,000 |
| Subordinated promissory note | 12 | 12,500 | 25,000 |
| | | 49,736 | 57,479 |
| Bank debt | 13 | 329,204 | 332,471 |
| Decommissioning liabilities | 14 | 100,941 | 71,523 |
| Deferred tax liability | 15 | 124,129 | 126,315 |
| | | 604,010 | 587,788 |
| **COMMITMENTS AND SUBSEQUENT EVENTS** | 21, 22 | | |
| **SHAREHOLDERS' EQUITY** | | | |
| Share capital | 16 | 763,788 | 760,020 |
| Contributed surplus | | 21,068 | 15,765 |
| Accumulated other comprehensive income | | 414 | 571 |
| Retained earnings (deficit) | | (241,446) | (180,551) |
| | | 543,824 | 595,805 |
| | | 1,147,834 | 1,183,593 |

See accompanying notes to these financial statements.

On behalf of the Board:

**GEORGE F. FINK**
Director

**RODGER A. TOURIGNY**
Director

# STATEMENT OF COMPREHENSIVE LOSS

| FOR THE YEARS ENDED DECEMBER 31<br>($ 000s, except $ per share) | Note | 2016 | 2015 |
|---|---|---|---|
| **REVENUE** | | | |
| Oil and gas sales, net of royalties | 17 | 160,082 | 183,878 |
| Other income | 18 | 233 | 328 |
| | | 160,315 | 184,206 |
| **EXPENSES** | | | |
| Production | | 54,503 | 55,215 |
| Office and administration | | 2,584 | 3,302 |
| Employee compensation | | 3,755 | 3,905 |
| Finance costs | 5 | 20,004 | 14,199 |
| Share-option compensation | 16 | 5,818 | 4,270 |
| Depletion and depreciation | 8 | 100,992 | 101,150 |
| Exploration and evaluation | 7 | - | 183 |
| Impairment of oil and gas assets | 8 | 2,505 | - |
| | | 190,161 | 182,224 |
| **EARNINGS (LOSS) BEFORE INCOME TAXES** | | (29,846) | 1,982 |
| **TAXES** | | | |
| Current income tax expense (recovery) | 15 | (3,547) | (355) |
| Deferred income tax expense (recovery) | 15 | (2,164) | 11,417 |
| | | (5,711) | 11,062 |
| **NET LOSS FOR THE YEAR** | | (24,135) | (9,080) |
| **OTHER COMPREHENSIVE INCOME (LOSS)** | | | |
| Unrealized gain (loss) on investments | | 2,866 | (2,519) |
| Deferred taxes on unrealized (gain) loss on investments | | (387) | 296 |
| **OTHER COMPREHENSIVE INCOME (LOSS) FOR THE YEAR** | | 2,479 | (2,223) |
| **TOTAL COMPREHENSIVE LOSS FOR THE YEAR** | | (21,656) | (11,303) |
| **NET LOSS PER SHARE – BASIC AND DILUTED** | 16 | (0.73) | (0.28) |
| **COMPREHENSIVE LOSS PER SHARE – BASIC AND DILUTED** | 16 | (0.65) | (0.35) |

See accompanying notes to these financial statements.

# STATEMENT OF CASH FLOW

| FOR THE YEARS ENDED DECEMBER 31<br>($ 000s) | Note | December 31, 2016 | December 31, 2015 |
|---|---|---|---|
| **OPERATING ACTIVITIES** | | | |
| Net loss | | (24,135) | (9,080) |
| Items not affecting cash | | | |
| Deferred income taxes | | (2,164) | 11,417 |
| Share-option compensation | | 5,818 | 4,270 |
| Depletion and depreciation | | 100,992 | 101,150 |
| Exploration and evaluation expenditures | | - | 183 |
| Impairment of oil and gas assets | | 2,505 | - |
| Gain on sale of equipment | | (1) | - |
| Unwinding of the discount on decommissioning liabilities | 14 | 2,507 | 1,878 |
| Investment income | | (18) | (251) |
| Interest expense | | 17,497 | 12,321 |
| Change in non-cash working capital accounts: | | | |
| Accounts receivable | | (5,266) | 4,419 |
| Crude oil inventory | | (77) | 300 |
| Prepaid expenses | | 269 | (370) |
| Investment tax credit receivable | | - | (261) |
| Accounts payable and accrued liabilities | | (2,341) | (5,597) |
| Decommissioning expenditures | 14 | (2,795) | (187) |
| Interest paid | | (17,497) | (12,321) |
| **CASH PROVIDED BY OPERATING ACTIVITIES** | | 75,294 | 107,871 |
| **FINANCING ACTIVITIES** | | | |
| Increase (decrease) in bank debt | | (3,267) | 177,748 |
| Subordinated promissory note | | (12,500) | (15,000) |
| Issuance of common shares of private placement | | - | 31,162 |
| Share issue costs | | - | (105) |
| Stock option proceeds | | 3,253 | - |
| Dividends | | (39,807) | (63,607) |
| **CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES** | | (52,321) | 130,198 |
| **INVESTING ACTIVITIES** | | | |
| Investment income received | | 18 | 251 |
| Exploration and evaluation expenditures | 7 | - | (479) |
| Property, plant and equipment expenditures | 8 | (40,851) | (58,019) |
| Proceeds on sale of property | | 54 | - |
| Purchase of investments | | - | (12,221) |
| Proceeds on sale of investments | | 10,783 | 8,130 |
| Acquisition | 20 | - | (170,430) |
| Change in non-cash working capital accounts: | | | |
| Accounts payable and accrued liabilities | | 7,098 | (5,763) |
| Accounts receivable | | (75) | 462 |
| **CASH USED IN INVESTING ACTIVITIES** | | (22,973) | (238,069) |
| **NET CHANGE IN CASH IN THE YEAR** | | - | - |
| Cash, beginning of year | | - | - |
| **CASH, END OF YEAR** | | - | - |

See accompanying notes to these financial statements.

# STATEMENT OF CHANGES IN EQUITY

**FOR THE YEARS ENDED**
($ 000s, except number of shares outstanding)

| | Numbers of shares outstanding (Note 16) | Share capital (Note 16) | Contributed surplus[1] | Accumulated other comprehensive income (loss)[2] | Retained earnings (deficit) | Total shareholder's equity |
|---|---|---|---|---|---|---|
| **JANUARY 1, 2015** | 32,169,623 | 728,934 | 11,495 | 3,824 | (109,055) | 635,198 |
| Share-option compensation | | | 4,270 | | | 4,270 |
| Share issuances, private placement | 973,812 | 31,162 | | | | 31,162 |
| Share issue costs, net of tax | | (76) | | | | (76) |
| Comprehensive loss | | | | (2,223) | (9,080) | (11,303) |
| Transfer on realized gain on investments | | | | (1,191) | 1,191 | - |
| Deferred taxes on realized gain on investments | | | | 161 | | 161 |
| Dividends | | | | | (63,607) | (63,607) |
| **DECEMBER 31, 2015** | 33,143,435 | 760,020 | 15,765 | 571 | (180,551) | 595,805 |
| Share-option compensation | | | 5,818 | | | 5,818 |
| Exercise of options | 159,000 | 3,253 | | | | 3,253 |
| Comprehensive income (loss) | | | | 2,479 | (24,135) | (21,656) |
| Transfer to share capital on exercise of options | | 515 | (515) | | | - |
| Transfer on realized gain on investments | | | | (3,047) | 3,047 | - |
| Deferred taxes on realized gain on investments | | | | 411 | | 411 |
| Dividends | | | | | (39,807) | (39,807) |
| **DECEMBER 31, 2016** | 33,302,435 | 763,788 | 21,068 | 414 | (241,446) | 543,824 |

(1) Contributed surplus includes all amounts related to share-based payments.
(2) Accumulated other comprehensive income comprises of unrealized gains and losses on available-for-sale investments.

See accompanying notes to these financial statements.

# NOTES TO THE FINANCIAL STATEMENTS

As at and for the years ended December 31, 2016 and 2015.

## 1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. (Bonterra or the Company) is a public company listed on the Toronto Stock Exchange (the "TSX") and incorporated under the Business Corporations Act (Alberta). The address of the Company's registered office is Suite 901, 1015 – 4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

Bonterra operates in one industry and has only one reportable segment being the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

## 2. BASIS OF PREPARATION

### a) Statement of Compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).

The financial statements were authorized for issue by the Company's Board of Directors on March 14, 2017.

### b) Basis of Measurement

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payment transactions which are measured at fair value.

### c) Functional and Presentation Currency

The Company's functional and presentation currency is the Canadian dollar.

Foreign currency denominated monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the reporting date. Non-monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the period in which they occur.

### d) Significant Accounting Estimates and Judgments

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts. See Note 4 for more information.

### e) Future Accounting Pronouncements

In May 2014, the International Accounting Standards Board (IASB) issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. This standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has not yet assessed the impact, if any, that the new standard will have on its financial statements or whether to early adopt this new requirement.

In January 2016, the IASB issued IFRS 16 "Leases," which replaces IAS 17 "Leases." For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers." The standard is required to be adopted either retrospectively or using a modified retrospective approach. The Company has not yet assessed the impact, if any, that the new amended standard will have on its financial statements or whether to early adopt this new requirement.

## 3. SIGNIFICANT ACCOUNTING POLICIES

### a) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when the significant risks and rewards of ownership have been transferred to the customer. This generally occurs when the product is physically transferred into a third-party pipeline or when the delivery truck arrives at a customer's receiving location. Items such as royalties for crown, freehold, gross overriding (GORR) and

Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue.

Administration fee income is recorded when management services and office administration are provided (see related party disclosure Notes 6 and 11).

### b) Joint Arrangements

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's interests in such activities. A jointly controlled operation involves the use of assets and other resources of the Company and those of other venturers through contractual arrangements rather than through the establishment of a corporation, partnership or other entity. The Company has no interests in jointly controlled entities. The Company recognizes in its financial statements its interest in assets that it owns, the liabilities and expenses that it incurs and its share of income earned by the joint arrangement.

### c) Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first in first out basis at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, depletion and depreciation for the period and net realizable value is determined based on estimated sales price less transportation costs.

### d) Investments and Investment in Related Party

Investments and investment in related party consist of equity securities. The Company's investments are measured as fair value through other comprehensive income (FVTOCI), with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. Fair value is determined by multiplying the period end trading price of the investments by the number of common shares held as at period end.

### e) Exploration and Evaluation Assets

General exploration and evaluation (E&E) expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the asset. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment (PP&E). E&E assets are assessed for impairment annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not at amounts above their recoverable amounts.

### f) Property, Plant and Equipment

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

When commercial production in an area has commenced, PP&E properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable developed reserve life. Proved plus probable developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of proved plus probable developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

#### Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost; including expenditures such as drilling costs; the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset; and finance charges on qualifying assets that are directly attributable to bringing the asset into operation and to its present location.

#### Production Facilities

Production facilities are comprised of costs related to petroleum and natural gas plant and production equipment.

### Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income (loss). Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets' estimated economic lives, less estimated salvage value of the assets at the end of their useful lives.

These assets are depreciated on a declining balance method as follows:

| | |
|---|---|
| Production facilities | 10 percent per year |
| Furniture, fixtures and other equipment | 10 percent to 20 percent per year |

## g) Business Combinations and Goodwill

The purchase price used in a business combination is based on the fair value at the date of acquisition. The business combination is accounted for based on the fair value of the assets acquired and liabilities assumed. All acquisition costs are expensed as incurred. Contingent liabilities are recognized at fair value at the date of the acquisition, and subsequently re-measured at each reporting period until settled. The excess of cost over fair value of the net assets and liabilities acquired is recorded as goodwill.

## h) Impairment of Assets

### Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flow 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 flow discounted at the original effective interest rate. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as fair value through other comprehensive income (FVTOCI) is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

### Impairment of Non-financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets' carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E, PP&E and Goodwill) are grouped together into the smallest group of assets that generates cash flows from continuing use that are largely independent of the cash flow of other assets or groups of assets (the cash-generating unit or CGU). Goodwill is allocated to the CGU expected to benefit from the synergies of the combination. The recoverable amount of an asset or a CGU is the greater of its value-in-use (VIU) and its fair value less costs to sell (FVLCS). The Company has a core CGU composed of its Alberta properties and secondary CGUs for its British Columbia (BC) and Saskatchewan properties.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income (loss). Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

In respect of assets other than goodwill, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the impairment loss has reversed. If the amount of the impairment loss reverses in a subsequent period and the reversal can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized and recorded in the statement of comprehensive income (loss). An impairment loss in respect of goodwill cannot be reversed.

## i) Decommissioning Liabilities

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk free rates are dealt with prospectively by recording an adjustment to the decommissioning liabilities, and a corresponding adjustment to property, plant and equipment. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the liability can be made. On a periodic basis, management will review these estimates and changes and if there are any, they will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved plus probable developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and any remaining balance of actual costs is recorded in the statement of comprehensive income (loss).

### j) Income Taxes

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income (loss) or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each period end and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset or liability.

### k) Share-option Compensation

The Company accounts for share-option compensation using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Share-option payments are recognized through the statement of comprehensive income (loss) over the vesting period with a corresponding amount reflected in contributed surplus in equity. For awards issued in tranches that vest at different times, the fair value of each tranche is recognized over its respective vesting period.

At the grant date and at the end of each reporting period, the Company assesses and re-assesses for subsequent periods its estimates of the number of awards that are expected to vest and recognizes the impact of the revisions in the statement of comprehensive income (loss). Upon exercise of share-based options, the proceeds received net of any transaction costs and the fair value of the exercised share-based options is credited to share capital.

Employees may elect to have the Company settle any or all options vested and exercisable using a cashless equity settlement. In connection with any such exercise, an employee shall be entitled to receive, without any cash payment (other than the taxes required to be paid in connection with the exercise), whole shares of the Company. The number of shares under option multiplied by the difference of the fair value at the time of exercise less the option exercise price, divided by the fair value at the time of exercise, determines the number of whole shares issued.

### l) Financial Instruments

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost, financial liabilities at amortized costs; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest rate method.

Cash, account receivables and certain other long-term assets are classified as financial assets at amortized cost since it is the

Company's intention to hold these assets to maturity and the related cash flows are mainly payments of principle and interest. The Company's investments are measured at fair value through other comprehensive income (FVTOCI), with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. Accounts payable, accrued liabilities, and certain other long-term liabilities and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

## m) Fair Value Measurement

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related party, subordinated promissory note and bank debt on the statement of financial position are carried at amortized cost. Investments and investments in related party are carried at fair value. All of the investments are transacted in active markets. Bonterra determines the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

## n) Risk Management Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

## o) Net Earnings and Comprehensive Income Per Share

Per share amounts are calculated by dividing the net earnings or comprehensive income (loss) attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

## 4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGEMENTS

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. The following are the estimates and judgments applied by management that most significantly affect the Company's financial statements.

### Exploration and Evaluation Expenditures

Exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. Exploration and evaluation assets include undeveloped land and costs related to exploratory wells. The Company is required to make estimates and judgments about future events and circumstances regarding the future economic viability of extracting the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made, that the underlying reserves are not viable, the exploration and evaluation costs will be impaired and charged to net earnings.

### Impairment of Non-financial Assets

Property, plant and equipment (PP&E) and goodwill are aggregated into cash generating units (CGUs) based on their ability to generate largely independent cash flows and are assessed for impairment. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, and similar market risks. Oil and gas prices and other assumptions will change in the future, which may impact the Company's recoverable amounts and may therefore require a material adjustment to the carrying value of PP&E. The determination of the Company's CGUs is subject to management's judgment. The Company has a core CGU composed of its Alberta properties and secondary CGUs for its BC and Saskatchewan properties.

The recoverable amount of E&E, PP&E, and goodwill is determined based on the fair value less costs of disposal using a discounted cash flow model and is assessed at the cash generating unit ("CGU") level. The period the Company used to project cash flows is approximately 50 years or the CGUs reserve life. Growth in cash flow from a single well would be determined based on the extent of total reserves assigned, which is produced at declining rates over the estimated reserve life. The fair value measurement of the Company's E&E, PP&E, and goodwill is designated Level 2 on the fair value hierarchy.

For the year ended December 31, 2016, the Company performed an impairment test on all of its CGUs for any potential impairment or related recovery. In making these evaluations, the Company uses the following information;

1) The net present value of the pre-tax cash flows from oil and gas reserves of each CGU based on reserves estimated by the Company's independent reserve evaluator; and

Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

a) Reserves – Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

b) Crude oil and natural gas prices – Forward price estimates of the crude oil and natural gas prices are used in the cash flow model. Commodity prices used tend to be stable because short-term increases or decreases in prices are not considered indicative of long-term price levels, but nonetheless subject to change and the change could be material.

c) Discount rate – The Company uses a pre-tax discount rate of 10 percent that reflects risks specific to the assets for which the future cash flow estimates have not been adjusted. The discount rate was determined based on the Company's assessment of risk based on past experience. Changes in the general economic environment could result in material changes to this estimate.

The following table from external sources outlines the forecast benchmark commodity prices used in the impairment calculation as at December 31, 2016.

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027[2] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| WTI Crude oil $US/Bbl[1] | 55.00 | 65.00 | 70.00 | 71.40 | 72.83 | 74.28 | 75.77 | 77.29 | 78.83 | 80.41 | 82.02 |
| AECO C-Spot $Mmbtu[1] | 3.44 | 3.27 | 3.22 | 3.91 | 4.00 | 4.10 | 4.19 | 4.29 | 4.40 | 4.50 | 4.61 |
| Exchange rate US$/$Cdn | 0.78 | 0.82 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 | 0.85 |

(1) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, transportation and marketing costs and other factors specific to the Company's operations in performing the Company's impairment tests.

(2) Forecast benchmarks commodity prices are assumed to increase by 2.0% in each year after 2027 to end of the reserve life.

With the current key assumptions listed above, the Company performed impairment tests for each CGU and concluded that no reasonable change in the key assumptions, such as a 5 percent change in commodity prices or a 1 percent change in the discount rate, would result in an impairment being recorded, except for its secondary CGU of British Columbia (further details are disclosed in note 7 and 8).

### Reserves Estimation

The capitalized costs of oil and gas properties are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors and future oil and gas prices. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves.

### Risk Management Contract

The Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in net earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party futures quotes for commodities. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

### Share-option Compensation

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value requires the determination of the most appropriate valuation model for a grant, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk free interest rates, volatility and dividend yield.

### Decommissioning and Restoration Costs

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of the Company's oil and gas properties. Provisions for decommissioning liabilities are based on cost estimates which can vary in response to many factors including timing of abandonment, inflation, changes in legal requirements, new restoration techniques and interest rates.

### Income Taxes

The Company recognizes the net deferred tax benefit or expense related to deferred income tax assets or liabilities to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of investment tax credit receivable requires the Company to make significant estimates related to expectations of future taxable income. The provision for income taxes is based on judgments in applying income tax law and estimates of the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. The ability to realize on the deferred tax assets and investment tax credit receivable recorded on the balance sheet may be compromised to the extent that any interpretation of tax law is challenged or taxable income differs significantly from estimates.

Further details regarding accounting estimates and judgments are disclosed in Note 3.

## 5. FINANCE COSTS

A breakdown of finance costs for the years ended:

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Interest expense on bank debt | 16,708 | 10,390 |
| Interest expense on amounts owing to related party | 249 | 261 |
| Interest expense on subordinated promissory note and other | 540 | 1,670 |
| Unwinding of the fair value of decommissioning liabilities | 2,507 | 1,878 |
| | 20,004 | 14,199 |

## 6. INVESTMENT IN RELATED PARTY

The investment consists of 1,034,523 (December 31, 2015 – 1,034,523) common shares in Pine Cliff Energy Ltd. ("Pine Cliff"), a company with some common directors and some common management with Bonterra. The investment in Pine Cliff represents less than one percent ownership in the outstanding common shares of Pine Cliff and is recorded at fair value through other comprehensive income. The common shares of Pine Cliff trade on the TSX under the symbol PNE.

## 7. EXPLORATION AND EVALUATION ASSETS

| ($ 000s) | |
|---|---|
| **COST AND CARRYING AMOUNT** | |
| Balance at January 1, 2015 | 7,629 |
| Additions | 479 |
| Expiry of exploration and evaulation assets | (183) |
| **BALANCE AT DECEMBER 31, 2015** | 7,925 |
| Dispositions | (54) |
| Impairment (Note 8) | (798) |
| **BALANCE AT DECEMBER 31, 2016** | 7,073 |

On December 31, 2016 Bonterra recorded a $798,000 impairment on its E&E assets in the British Columbia CGU. This was a result of a decrease in commodity price forecasts, increase in forecasted operating costs and no currently planned future capital expenditures in this non-core area.

## 8. PROPERTY, PLANT AND EQUIPMENT

| **COST** ($ 000s) | **OIL AND GAS PROPERTIES** | **PRODUCTION FACILITIES** | **FURNITURE FIXTURES & OTHER EQUIPMENT** | **TOTAL PROPERTY PLANT & EQUIPMENT** |
|---|---|---|---|---|
| Balance at January 1, 2015 | 1,028,520 | 252,521 | 1,987 | 1,283,028 |
| Additions | 42,093 | 15,860 | 66 | 58,019 |
| Acquisition | 138,711 | 34,400 | - | 173,111 |
| Adjustment to decommissioning liabilities[1] | 13,359 | - | - | 13,359 |
| **BALANCE AT DECEMBER 31, 2015** | 1,222,683 | 302,781 | 2,053 | 1,527,517 |
| Additions | 28,564 | 12,258 | 29 | 40,851 |
| Adjustment to decommissioning liabilities[1] | 29,706 | - | - | 29,706 |
| **BALANCE AT DECEMBER 31, 2016** | 1,280,953 | 315,039 | 2,082 | 1,598,074 |

| **ACCUMULATED DEPLETION AND DEPRECIATION** ($ 000s) | **OIL AND GAS PROPERTIES** | **PRODUCTION FACILITIES** | **FURNITURE FIXTURES & OTHER EQUIPMENT** | **TOTAL PROPERTY PLANT & EQUIPMENT** |
|---|---|---|---|---|
| Balance at January 1, 2015 | (305,742) | (73,866) | (1,429) | (381,037) |
| Depletion and depreciation | (84,800) | (16,250) | (100) | (101,150) |
| Disposal and other | 57 | - | - | 57 |
| **BALANCE AT DECEMBER 31, 2015** | (390,485) | (90,116) | (1,529) | (482,130) |
| Depletion and depreciation | (84,455) | (16,452) | (85) | (100,992) |
| Disposal and other | (112) | - | - | (112) |
| Impairment | (1,366) | (341) | - | (1,707) |
| **BALANCE AT DECEMBER 31, 2016** | (476,418) | (106,909) | (1,614) | (584,941) |

| **CARRYING AMOUNTS AS AT:** ($ 000s) | | | | |
|---|---|---|---|---|
| December 31, 2015 | 832,198 | 212,665 | 524 | 1,045,387 |
| **DECEMBER 31, 2016** | 804,535 | 208,130 | 468 | 1,013,133 |

(1) Adjustment to decommissioning liabilities is due to an increase in the inflation rate, risk free rate and a change in estimate on decommissioning costs (See Note 14).

The impairment of property, plant and equipment assets and any subsequent reversal of such impairment losses are recognized in the statement of comprehensive loss. Due to decreasing commodity price forecasts and higher operating cost forecasts in one of its CGUs, Bonterra determined that there were indicators of impairment at December 31, 2016 and completed impairment test on all of its CGUs. Consequently, Bonterra recorded impairment charges totaling $1,707,000 related to the secondary British

Columbia CGU. The recoverable amounts used in the impairment tests, based on fair value less cost to sell, related to this CGU were calculated using a proved plus probable reserves at a pre-discount rate of 10 percent (2015 – 10 percent). As well, Bonterra recorded impairment charges totaling $798,000 on its E&E assets, also related to its British Columbia CGU for a total impairment loss of $2,505,000. As of December 31, 2016, the recoverable amount of the British Columbia CGU is $539,000.

There were no impairment losses or reversals recorded in the statement of comprehensive loss for the year ended December 31, 2015.

## 9. GOODWILL

The amount recorded as goodwill has all been allocated to the primary CGU, Alberta, Canada. There was no impairment loss recorded in the statement of comprehensive income (loss) for the years ended December 31, 2016 and 2015.

## 10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Accounts payable | 18,710 | 15,130 |
| Accrued liabilities | 6,526 | 5,349 |
| | 25,236 | 20,479 |

## 11. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2016, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2015 – $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8$^{th}$ of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during 2016 was $249,000 (December 31, 2015 – $261,000).

The Company received a management fee of $15,000 plus the reimbursement of certain administrative expenses for the year ended December 31, 2016 (December 31, 2015 – $60,000) for management services and office administration from Pine Cliff Energy Ltd. ("Pine Cliff"). This fee has been included in other income. On April 1, 2016, the management agreement was terminated. As at December 31, 2016, the Company had an account receivable from Pine Cliff of $51,000 (December 31, 2015 – $293,000).

### Compensation for Key Management Personnel

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Compensation | 917 | 1,407 |
| Share-based payments | 2,331 | 1,595 |
| Total compensation | 3,248 | 3,002 |

Key management personnel are those persons, including all directors, having authority and responsibility for planning, directing and controlling the activities of the Company.

## 12. SUBORDINATED PROMISSORY NOTE

As at December 31, 2016, Bonterra had $12,500,000 (December 31, 2015 – $25,000,000) outstanding on a subordinated note to a private investor. The terms of the subordinated promissory note are that it bears interest at five percent and is repayable after thirty days' written notice by either party. Security consists of a floating demand debenture over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on the subordinated promissory note during the year was $540,000 (December 31, 2015 – $974,000). The Company repaid $10,000,000 on January 22, 2016. On July 27, 2016 the Company repaid $2,500,000 and amended the agreement that resulted in increasing the interest rate to five percent annually from three percent annually.

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility.

## 13. BANK DEBT

As at December 31, 2016, the Company has bank facilities consisting of a $330,000,000 (December 31, 2015 – $375,000,000) syndicated revolving credit facility and a $50,000,000 (December 31, 2015 – $50,000,000) non-syndicated revolving credit facility, for total credit facilities of $380,000,000. Amounts drawn under the credit facilities at December 31, 2016 were $329,204,000 (December 31, 2015 – $332,471,000). Amounts borrowed under the credit facilities bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 1.00 percent and 4.25 percent, depending on the type of borrowing and the Company's consolidated debt to EBITDA ratio. EBITDA is defined as net income for the period excluding finance costs, provision for current and deferred taxes, depletion and depreciation, share-option compensation, gain or loss on sale of assets and impairment of assets. The terms of the revolving credit facilities provided that the loan is revolving to April 30, 2017, with a maturity date of April 30, 2018, subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limits of the credit facilities are reviewed semi-annually on or before April 30 and October 31 each year based on the lender's interpretation of the Company's reserves, future commodity prices and costs. On October 26, 2016, the Company renewed its available lending limit at $380,000,000.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $2,990,000 were issued as at December 31, 2016 (December 31, 2015 – $1,950,000). Security for credit facilities consists of various and floating demand debentures totaling $750,000,000 (December 31, 2015 – $750,000,000) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

The following is a list of the material covenants on the credit facilities:

- The Company cannot exceed $380,000,000 in consolidated debt (excluding accounts payable and accrued liabilities). As at December 31, 2016 consolidated debt is $353,703,000.
- Dividends paid in the current quarter shall not exceed 80 percent of the available cash flow for the preceding four fiscal quarters divided by four, which is calculated as 41 percent for the current quarter.

Available cash flow is defined to be cash provided by operating activities excluding the change in non-cash working capital and decommissioning liabilities settled and including investment income received and all net proceeds of dispositions included in cash used in investing activities. At December 31, 2016, the Company is in compliance with all covenants.

## 14. DECOMMISSIONING LIABILITIES

At December 31 2016, the estimated total undiscounted amount required to settle the decommissioning liabilities was $312,436,000 (December 31, 2015 – $232,413,000). The provision has been calculated assuming a 2.0 percent inflation rate (December 31, 2015 – 1.5 percent inflation rate). These obligations will be settled at the end of the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of 2.95 percent (December 31, 2015 – 2.90 percent).

Changes to decommissioning liabilities were as follows:

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| **DECOMMISSIONING LIABILITIES, JANUARY 1** | 71,523 | 53,792 |
| Acquistion (Note 20) | - | 2,681 |
| Adjustment to decommissioning liabilities[1] | 29,706 | 13,359 |
| Liabilities settled during the period | (2,795) | (187) |
| Unwinding of the discount on decommissioning liabilities | 2,507 | 1,878 |
| **DECOMMISSIONING LIABILITIES, END OF YEAR** | 100,941 | 71,523 |

(1) Adjustment to decommissioning liabilities is due to a change in the inflation rate, risk free rate and estimated decommissioning costs.

## 15. INCOME TAXES

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Deferred tax asset (liability) related to: | | |
| Investments | (85) | (110) |
| Exploration and evaluation assets and property, plant and equipment | (159,670) | (148,961) |
| Investment tax credits | (2,385) | (2,385) |
| Decommissioning liabilities | 27,251 | 19,311 |
| Corporate tax losses carried forward | 10,393 | 4,983 |
| Share issue costs | 281 | 737 |
| Corporate capital tax losses carried forward | 8,698 | 9,138 |
| Unrecorded benefits of Capital tax losses carried forward | (8,612) | (9,028) |
| Deferred tax asset (liability) | (124,129) | (126,315) |

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Earnings (loss) before taxes | (29,846) | 1,982 |
| Combined federal and provincial income tax rates | 27.00% | 26.01% |
| Income tax provision calculated using statutory tax rates | (8,058) | 515 |
| Increase (decrease) in taxes resulting from: | | |
| Change in statutory tax rates(1) | 4 | 8,490 |
| Share-option compensation | 1,571 | 1,110 |
| Realized gain on sale of investments | 411 | 161 |
| Change in estimates and other | 361 | 786 |
| | (5,711) | 11,062 |

(1) Effective July 1, 2015 the combined federal and provincial income tax rate for Bonterra is approximately 27.00% due to the provincial tax rate for Alberta, Canada increasing from 10% to 12%.

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

| ($ 000s) | Rate of Utilization (%) | Amount |
|---|---|---|
| Undepreciated capital costs | 20-100 | 95,734 |
| Eligible capital expenditures | 7 | 2,245 |
| Share issue costs | 20 | 1,043 |
| Canadian oil and gas property expenditures | 10 | 163,071 |
| Canadian development expenditures | 30 | 158,764 |
| Canadian exploration expenditures | 100 | 8,063 |
| Federal income tax losses carried forward(1) | 100 | 54,421 |
| Provincial income tax losses carried forward(2) | 100 | 18,598 |
| | | 501,939 |

(1) Federal income tax losses carried forward expire in the following years; 2035 – $18,433,000; 2036 – $35,988,000.

(2) Provincial income tax losses carried forward expire in 2036.

The Company has $8,834,000 (December 31, 2015 – $8,834,000) of investment tax credits that expire in the following years; 2021 – $1,824,000; 2022 – $1,735,000; 2023 – $1,097,000; 2024 – $1,241,000; 2025 – $1,323,000; 2026 – $1,105,000; 2027 – $410,000; and 2035 – $99,000.

The Company has $64,435,000 (December 31, 2015 – $67,691,000) of capital losses carried forward which can only be claimed against taxable capital gains.

The $3,547,000 current tax recovery for 2016 is comprised of provincial income tax losses that were carried back to recover prior provincial income tax paid. The Company has received payment of $1,771,000 with $1,776,000 remaining in accounts receivable.

## 16. SHAREHOLDERS' EQUITY

### Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

| | December 31, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| Issued and fully paid – common shares | Number | Amount ($ 000s) | Number | Amount ($ 000s) |
| Balance, beginning of year | 33,143,435 | 760,020 | 32,169,623 | 728,934 |
| Share issuances, private placement | - | - | 973,812 | 31,162 |
| Share issue costs, net of tax | | - | | (76) |
| Issued pursuant to the Company's share option plan | 159,000 | 3,253 | - | - |
| Transfer from contributed surplus to share capital | | 515 | - | - |
| **Balance, end of year** | 33,302,435 | 763,788 | 33,143,435 | 760,020 |

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The weighted average common shares used to calculate basic and diluted net earnings per share for the year ended December 31 is as follows:

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Basic shares outstanding | 33,255,957 | 32,641,855 |
| Dilutive effect of share options[1] | 67,328 | - |
| Diluted shares outstanding | 33,323,285 | 32,641,855 |

(1) The Company did not include 2,081,000 share options (December 31, 2015 – 2,955,500) in the dilutive effect of share options calculation as these share options were anti-dilutive.

For the year December 31, 2016, the Company declared and paid dividends of $39,807,000 ($1.20 per share) (December 31, 2015 – $63,607,000 ($1.95 per share)).

The Company provides an equity settled option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,330,244 (December 31, 2015 – 3,314,344) common shares. The exercise price of each option granted cannot be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2016, and changes during the period ended on those dates is presented below:

| | Number of options | Weighted average exercise price |
|---|---|---|
| At January 1, 2015 | 2,111,500 | $ 54.94 |
| Options granted | 1,772,500 | 28.15 |
| Options expired | (928,500) | 50.46 |
| At December 31, 2015 | 2,955,500 | $ 40.28 |
| Options granted | 935,000 | 25.50 |
| Options exercised | (159,000) | 20.46 |
| Options forfeited | (152,500) | 43.16 |
| Options expired | (842,000) | 58.86 |
| **AT DECEMBER 31, 2016** | 2,737,000 | $ 30.50 |

The following table summarizes information about options outstanding at December 31, 2016:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of exercise prices | Number outstanding at December 31, 2016 | Weighted-average remaining contractual life | Weighted-average exercise price | Number exercisable at December 31, 2016 | Weighted-average exercise price |
| $ 17.00 – 30.00 | 1,558,000 | 1.3 years | $ 23.48 | 615,000 | $ 20.46 |
| 30.01 – 45.00 | 904,000 | 0.8 years | 34.55 | 8,000 | 32.00 |
| 45.01 – 65.00 | 275,000 | 0.5 years | 56.96 | 144,000 | 56.35 |
| $ 17.00 – 65.00 | 2,737,000 | 1.0 years | $ 30.50 | 767,000 | $ 27.32 |

The Company records compensation expense over the vesting period, which ranges between one to three years, based on the fair value of options granted to employees, directors and consultants. In 2016, the Company granted 935,000 stock options with an estimated fair value of $5,040,000 or $5.39 per option using the Black-Scholes option pricing model with the following key assumptions:

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Weighted-average risk free interest rate (%)[1] | 0.58 | 0.48 |
| Expected life (years) | 1.0 | 1.5 |
| Weighted-average volatility (%)[2] | 59.91 | 39.93 |
| Forfeiture rate (%) | 8.62 | 9.24 |
| Weighted average dividend yield (%) | 4.73 | 6.84 |

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for one, two, and three year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

## 17. OIL AND GAS SALES, NET OF ROYALTIES

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Oil and gas sales | 169,863 | 197,239 |
| Less: | | |
| Crown royalties | (5,917) | (8,007) |
| Freehold, gross overriding royalties and other | (3,864) | (5,354) |
| Oil and gas sales, net of royalties | 160,082 | 183,878 |

## 18. OTHER INCOME

| ($ 000s) | December 31, 2016 | December 31, 2015 |
|---|---|---|
| Investment income | 18 | 251 |
| Administrative income | 214 | 77 |
| Gain on sale of equipment | 1 | - |
| Other income | 233 | 328 |

## 19. FINANCIAL AND CAPITAL RISK MANAGEMENT

### Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Common share investments
- Due to related party
- Bank debt
- Subordinated promissory note

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, liquidity risk and equity price risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

The Company may enter into various risk management contracts to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

### Capital Risk Management

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of net debt (total debt adjusted for working capital) to cash flow from operating activities. This ratio is calculated using each quarter end net debt divided by the preceding twelve months cash flow. Management believes that a net debt level as high as one and a half year's cash flow is still an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs. During the current year the Company had a net debt to cash flow level of 4.7:1. The increase in net debt to cash flow ratio is primarily due to the acquisition of the Pembina Assets (see acquisition Note 20) and low commodity prices realized in 2015 and 2016. To manage its bank debt during a period of low commodity prices the Company significantly reduced planned capital expenditures for the 2015 and 2016 fiscal years and in February 2015 reduced the monthly dividend by $0.15 per common share. In January of 2016 the Company reduced the monthly dividend by a further $0.05 to $0.10 per common share. On July 8, 2015, the Company raised approximately $31 million in equity by way of a private placement (see shareholders' equity Note 16).

Section (a) of this note provides the Company's debt to cash flow from operations.

Section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

#### a) Net Debt Ratio

The net debt and cash flow amounts as of December 31, 2016 are as follows:

| ($ 000s) | |
|---|---|
| Bank debt | 329,204 |
| Accounts payable and accrued liabilities | 25,236 |
| Due to related party | 12,000 |
| Subordinated promissory note | 12,500 |
| Current assets | (24,815) |
| Net debt | 354,125 |
| Cash flow from operations | 75,294 |
| Net debt ratio | 4.7 |

b) Risks and Mitigation

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

## Commodity Price Risk

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided that at least in the near term it will not participate in any commodity price agreements. The Company will assume full risk in respect of commodity prices.

## Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $330,000,000 syndicated revolving operating line, $50,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $12,500,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, are at bank prime plus or minus various percentages as well as by means of banker's acceptances (BAs) within the Company's credit facility. The subordinated promissory note is at a fixed interest rate of five percent. The Company manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its BAs but in no circumstances do the terms exceed six months.

## Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $2,491,000.

## Equity Price Risk

Equity price risk refers to the risk that the fair value of the investments and investment in related party will fluctuate due to changes in equity markets. Equity price risk arises from the realizable value of the investments that the Company holds which are subject to variable equity market prices which on disposition gives rise to a cash flow equity price risk. The Company will assume full risk in respect of equity price fluctuations.

## Foreign Exchange Risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. Management, in agreement with the Board of Directors, decided that at least in the near term it will not use commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

## Credit Risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the statement of financial position. To help mitigate this risk:

- The Company only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and
- Agreements for product sales are primarily on 30 day renewal terms.

Of the $20,774,000 accounts receivable balance at December 31, 2016 (December 31, 2015 – $15,433,000) over 80 percent (2015 – 83 percent) relates to product sales with national and international oil and gas companies.

The Company assesses quarterly if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2016, there was no material impairment provision required on any of the financial assets of the Company. The Company does have a credit risk exposure as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days' notice if payments are not received.

At December 31, 2016, approximately $2,166,000 or 10 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2015 – $1,077,000 or 7 percent). The majority of these accounts are due from various joint venture partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2016 is $354,000 (December 31, 2015 – $365,000) with the expense being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable. There are no material financial assets that the Company considers past due.

## Liquidity Risk

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company maintains bank facilities determined by a portfolio of high-quality, long reserve life oil and gas assets.

The Company has the following maturity schedule for its financial liabilities and commitments:

| ($ 000s) | Recognized on Financial Statements | Less than 1 year | Over 1 year to 9 years |
|---|---|---|---|
| Accounts payable and accrued liabilities | Yes – Liability | 25,236 | - |
| Due to related parties | Yes – Liability | 12,000 | - |
| Suboridinated promissory note | Yes – Liability | 12,500 | - |
| Bank Debt | Yes – Liability | - | 329,204 |
| Firm service commitments | No | 1,384 | 8,086 |
| Office lease commitments | No | 522 | 3,152 |
| Total | | 51,642 | 340,442 |

## 20. ACQUISITION

On April 15, 2015, the Company acquired Cardium focused oil and gas assets in the Pembina area of Alberta, including upper zones (the "Pembina Assets") that are complimentary to its existing Cardium oil and gas asset base. Cash consideration for these assets was $170,430,000. The results of the Pembina Assets have been included in these financial statements since that date. The Pembina Assets contributed oil and gas sales, net of royalties, of $20,667,000 and operating expenses of $10,448,000 for the period from April 15, 2015 to December 31, 2015. If the acquisition had occurred on January 1, 2015, total oil and gas sales, net of royalties, would have been approximately $28,127,000 and the total production costs would have been approximately $14,761,000 for the year ended December 31, 2015.

The acquisition has been accounted for using the acquisition method, and the purchase price was allocated to the assets acquired and the liabilities assumed as follows:

| Net assets acquired: | ($ 000s) |
|---|---|
| Property, plant and equipment | 173,111 |
| Decommissioning liabilities | (2,681) |
| Total | 170,430 |

| Consideration: | |
|---|---|
| Cash | 170,430 |
| Total purchase price | 170,430 |

## 21. COMMITMENTS

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to eight years. The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 6.9 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum payments for the firm service gas transportation agreements using current tariff rates and the non-cancellable building and office equipment leases as at December 31, 2016 are as follows:

| ($ 000s) | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Firm service commitments | 1,384 | 1,396 | 1,373 | 1,268 | 1,168 | 2,881 | 9,470 |
| Office lease commitements | 522 | 503 | 506 | 535 | 535 | 1,073 | 3,674 |
| Total | 1,906 | 1,899 | 1,879 | 1,803 | 1,703 | 3,954 | 13,144 |

## 22. SUBSEQUENT EVENTS

Subsequent to December 31, 2016, the Company declared the following dividends:

| Date declared | Record date | $ per share | Date payable |
|---|---|---|---|
| January 3, 2017 | January 16, 2017 | 0.10 | January 31, 2017 |
| February 1, 2017 | February 15, 2017 | 0.10 | February 28, 2017 |
| March 1, 2017 | March 15, 2017 | 0.10 | March 31, 2017 |

# CORPORATE INFORMATION

## BOARD OF DIRECTORS

G. F. Fink – Chairman
G. J. Drummond
R. M. Jarock
C. R. Jonsson
R. A. Tourigny

## OFFICERS

G. F. Fink, CEO and Chairman of the Board
R. D. Thompson, CFO and Corporate Secretary
A. Neumann, Chief Operating Officer
B. A. Curtis, Senior Vice President, Business Development

## REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada

## AUDITORS

Deloitte LLP

## SOLICITORS

Borden Ladner Gervais LLP

## BANKERS

CIBC
National Bank of Canada
TD Securities
Alberta Treasury Branch
Business Development Bank of Canada

## HEAD OFFICE

901, 1015 – 4th Street SW
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Email: info@bonterraenergy.com

## WEBSITE

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