BONAVISTA

ENERGY CORPORATION

# ANNUAL REPORT

# - 2018 -

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# OVERVIEW

Bonavista Energy Corporation is an intermediate, dividend-paying, Canadian oil and natural gas producer headquartered in Calgary, Alberta.

The year 2018 marks the 21st year of operations. Over the past 21 years, Bonavista has remained committed to being a responsible corporate steward of Canada's natural resources despite commodity price volatility and uncertainty inherent in the energy sector. Bonavista's continued focus has been on creating maximum shareholder value through the efficient development of high-quality natural gas, natural gas liquids and oil assets in the Western Canadian Sedimentary Basin ("WCSB").

Bonavista prides itself on being one of the most responsible and efficient producers in the Canadian energy sector, the result of bringing together excellent people who consistently find better ways of doing things.

References to Bonavista, our, we, and the Corporation used throughout this report refer to Bonavista Energy Corporation. All amounts presented are expressed in Canadian dollars ("CDN") unless otherwise indicated.

1997 - 2017
BONAVISTA
ENERGY CORPORATION

## MESSAGE TO SHAREHOLDERS

**"In 2018, we celebrated our 21st anniversary of efficient operations in the Western Canadian Sedimentary Basin, a basin abundant with world-class natural resources being developed under stringent environmental regulations and social standards that are second to none."** stated Jason Skehar, president and CEO of Bonavista.

Notwithstanding the headwinds our sector faced in 2018, the future net revenue attributable to our gross proved plus probable reserves ("2P") discounted at a rate of 10%, before deducting future income tax expenses ("BTNPV10")[2], increased seven percent to $2.64 billion. The increase in reserve value was achieved while spending less than 50% of our adjusted funds flow[1] on our capital program to drill for and acquire reserves. After adjusting our 2P BTNPV10 for net debt[1] as at December 31, 2018, our net asset value per share increased 10% to $6.92 per share.

Despite natural gas prices at AECO weakening to $1.44 per GJ for the year, a 22-year low, we generated $63.3 million of adjusted funds flow[1] in excess of net capital expenditures[1] required to maintain production at 68,000 boe per day in the final three quarters of the year. In 2018, $60.0 million was directed towards debt repayment which contributed to reducing net debt[1] by $475 million over the past three years, significantly enhancing financial flexibility for the future.

We strategically allocated our exploration and development ("E&D") capital to our highest quality development projects, focusing on opportunities rich in natural gas liquids ("NGLs"). This allowed us to increase our production weighting of natural gas liquids and oil to 31% in the fourth quarter, up from 29% in the prior year period. Furthermore, we replaced 306% of our 2018 NGL production with 2P NGL reserves.

Our operating, financial and reserve highlights in 2018 prove the quality, resilience and sustainability of our asset base. The strategy deployed in 2018 has undoubtedly enhanced our ability to create shareholder value in the future.

## 2019 OUTLOOK AND CAPITAL PLANS

The western Canadian natural gas sector has experienced numerous distressed pricing events throughout 2018:

- For 2018, Canadian AECO natural gas prices averaged C$1.44 per GJ, a 22-year low at the AECO hub;
- In the fourth quarter, Canadian natural gas prices averaged US$1.43 per mmbtu a 61% discount to the average natural gas price in the US of US$3.64 per mmbtu for the same period; and
- In December, western Canadian AECO prices averaged C$1.67 per mcf while prices immediately south and east of our western Canadian borders were C$4.80 per mcf and C$4.93 per mcf, respectively.

The quality of our abundant natural gas resources in western Canada are competitive with most natural gas plays in North America. The challenge we face in Canada is the lack of pipeline and export egress for the product we produce. Our competitive supply is being constrained by exhaustive regulation creating a lack of export infrastructure to our borders. This, in turn is causing severe discounts in Canadian pricing and providing a competitive advantage to our most fierce competitor, the United States of America ("US"). This disadvantage has become clear with 50% growth in US natural gas production from 2007 to 2015 while western Canadian production has shrunk during the same time period.

Major transformations are underway for the global energy sector, from growing electrification to the globalization of natural gas markets. Growth in global gas trade is accelerating given the accessibility of natural gas with the increasing investment in liquefied natural gas ("LNG") and policy efforts to combat air pollution, both key drivers of natural gas demand. As developing economies replace coal-fired generation with modern and efficient gas-fired generation, emissions can be reduced.

Natural gas is clearly becoming the fossil fuel of choice around the globe. Annual volumes of LNG exported around the world has grown significantly from approximately 14 bcf per day in 2001 to approximately 46 bcf per day in 2018. Current forecasts are that by 2035, world LNG production will reach approximately 100 bcf per day. With up to 1,800 tcf of marketable resources in place in Canada, clearly, we as Canadians have an opportunity like no other to supply the rest of the world with clean, environmentally and socially responsible energy.

While natural gas use in advanced economies is expected to grow over the next 20 years, Asia is expected to remain the primary driver of demand growth. With world demand for natural gas currently on the rise, China is expected to outpace Japan as the world's largest gas-importing country this year with imports continuing to grow and expected to catch the level of the EU by 2040. There should be no other country that can compete like Canada to provide LNG to China, a developing country looking for a reliable, responsible source of clean energy.

The US is also responding much quicker to the growth in world demand for LNG. While both Canada and the US began in a similar position in 2010, the US will be exporting in excess of nine bcf per day by year-end. Unfortunately, here in Canada we cannot share the same success story.

Fortunately, the door has recently been opened with a positive final investment decision in late 2018 for the initial phase of LNG Canada on the west coast of our country. The first phase of this project, calling for up to two bcf per day of demand has initial exports scheduled for 2024. This announcement has provided an increased level of confidence in export markets for Canadian natural gas. We expect to see updates in 2019 on other LNG export project proposals, which if met with cooperation from our policy makers and the citizens of Canada, could add up to four bcf per day of incremental natural gas exports in due course.

In 2018, we proudly celebrated our 21st year of efficient operations in western Canada creating value for our shareholders through financial stewardship, sustainable development and cost-effective production of high quality Canadian natural resources. Canadian energy production standards are global benchmarks for sustainable development and environmental protection. Canadian natural gas is the one of the most responsible and environmentally friendly hydrocarbons in the world. It is a reliable, efficient and affordable source of energy developed under leading regulatory and labour standards. Substitution of higher carbon fuels with greater use of Canadian natural gas by international consumers is a net global environmental benefit.

Our business philosophy in 2019 will be similar to our approach in 2018. In the current subdued commodity price environment, we see little economic incentive to grow our business. Hence, we intend to allocate capital to our highest quality development opportunities whereby we maintain production from January to December. We will focus on maximizing cash flow from operating activities with a goal to generate adjusted funds flow(1) in excess of what is required to maintain our forecasted production. We plan to allocate these funds to reduce our net debt(1) to strengthen our balance sheet and enhance our future financial flexibility. In addition, we intend to continue investing in land and infrastructure in the current environment to prepare our asset portfolio for maximum value creation in the future.

Our 2019 capital program is forecasted to range between $130 and $170 million, of which approximately $110 to $130 million will be allocated to our value capital program. Approximately, three quarters of our development capital is set to be spent in our West Central area with the remainder being allocated to the Deep Basin core area. With minimal commitments across our portfolio, we intend to remain flexible with capital allocation and responsive to changing commodity prices. The remaining $20 to $40 million will be allocated to support capital intended to strengthen our asset portfolio for the future.

Our predictable asset base and reliable capital program allows us to maintain our exit production year-over-year between 67,000 and 69,000 boe per day. Continued ethane rejection forecasted in 2019 and a significant third party turnaround season negatively impacts our forecasted annual production. In June, we are forecasting a production curtailment of approximately 10,000 boe per day due to turnaround activity alone. Hence, we expect annual production to be between 65,000 and 69,000 boe per day.

Currently, we have approximately 60% of our forecasted 2019 production hedged with hedges in place for all products that we produce. Specifically, our natural gas marketing strategy has minimized our exposure to the daily AECO hub with less than 17% of our forecasted natural gas production throughout the summer of 2019 being exposed to AECO volatility. Lastly, we have approximately 70 mmcf per day of our natural gas diversified to sales points beyond AECO.

The 2019 plan(4) is designed to generate approximately $170 to $200 million of adjusted funds flow(1) at current strip prices and is expected to lead to the reduction of net debt(1) reduction for the fourth consecutive year.

We thank our employees for their commitment and dedication, our Board of Directors for their guidance and our shareholders for their long-term support.

**On behalf of the Board of Directors,**

Jason E. Skehar
President and Chief Executive Officer

February 14, 2019
Calgary, Alberta

Section Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) The net present value of future net revenue attributable to Bonavista's gross proved plus probable reserves at December 31, 2018, before deducting future income tax expenses, calculated at a discount rate of 10% using the forecast price and cost assumptions of GLJ Petroleum Consultants Ltd. ("GLJ"). Reference should be made to the section entitled "Oil and Gas Advisories".
(3) Basic per share calculations includes exchangeable shares which are convertible into common shares on certain terms and conditions.
(4) Reference should be made to section titled "2019 Guidance" in Management's Discussion and Analysis ("MD&A") for the three months and year ended December 31, 2018.

## FINANCIAL AND OPERATING RESULTS

### 2018 FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- Maintained quarter-over-quarter production at 68,011 boe per day, despite approximately 1,600 boe per day of unscheduled production curtailments, largely due to third party processing interruptions and volatile AECO natural gas prices caused by maintenance on the Nova Gas Transmission ("NGTL") system;
- Acquired approximately 13,500 prospective net acres and 500 boe per day of liquids rich production offsetting our operations in the Hoadley Glauconite trend near Willesden Green;
- Drilled five gross (4.3 net) wells in the fourth quarter;
- Increased NGL production to 19,131 per day, a seven percent increase over the prior quarter and the highest quarterly volume in 2018;
- Reduced cash costs[1] to $9.27 per boe, a two percent improvement over prior quarter and the lowest quarterly cost in 2018;
- Directed 30% of our exploration and development expenditures to support capital, primarily related to spending on crown land and infrastructure improvement, that will add value beyond 2018; and
- Hedged an incremental 95 mmcf per day for 2019 and contracted an incremental 20 mmcf per day to sales markets beyond AECO effective April 1, 2019.

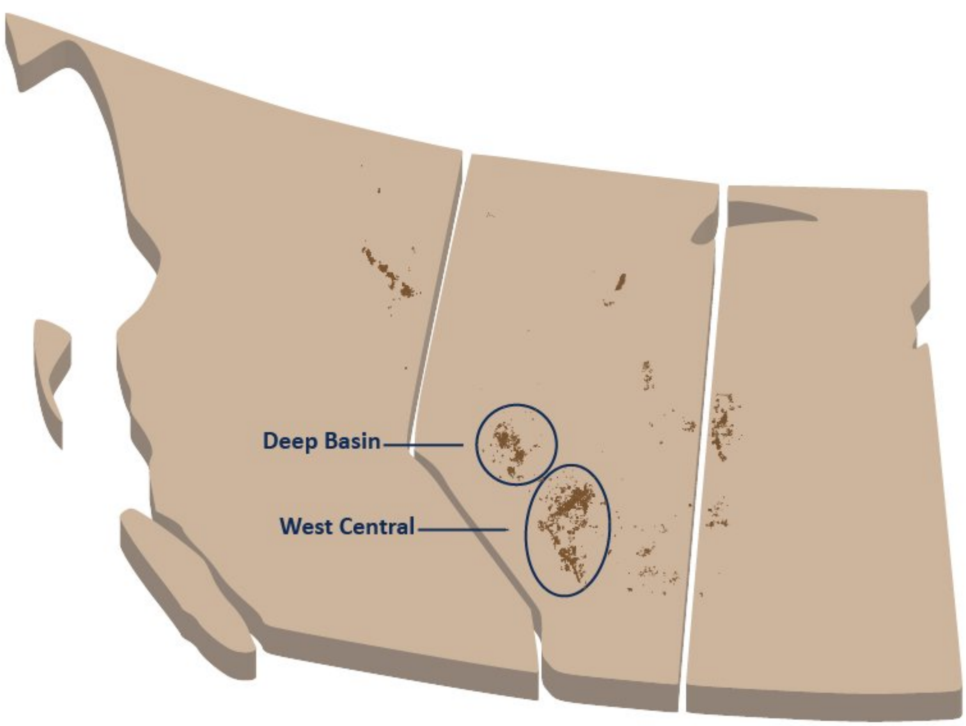
| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Financial** | | | | | | |
| ($ thousands, except per boe and per share amounts) | | | | | | |
| Production revenues | **124,302** | 147,188 | (16)% | **514,967** | 553,002 | (7)% |
| Net income (loss) | **81,227** | (159,149) | 151 % | **11,815** | (27,930) | 142 % |
| Per share[2] | **0.31** | (0.62) | 150 % | **0.05** | (0.11) | 145 % |
| Cash flow from operating activities | **77,581** | 94,515 | (18)% | **291,191** | 325,619 | (11)% |
| Per share[2] | **0.30** | 0.37 | (19)% | **1.13** | 1.27 | (11)% |
| Adjusted funds flow[1] | **61,075** | 86,108 | (29)% | **259,595** | 301,988 | (14)% |
| Per share[2] | **0.23** | 0.33 | (30)% | **1.00** | 1.18 | (15)% |
| Dividends declared | **2,555** | 2,518 | 1 % | **10,168** | 10,040 | 1 % |
| Per share | **0.01** | 0.01 | — % | **0.04** | 0.04 | — % |
| Total assets | **2,923,709** | 2,959,470 | (1)% | **2,923,709** | 2,959,470 | (1)% |
| Shareholders’ equity | **1,552,184** | 1,539,461 | 1 % | **1,552,184** | 1,539,461 | 1 % |
| Long-term debt | **801,625** | 800,544 | — % | **801,625** | 800,544 | — % |
| Net debt[1] | **835,905** | 840,173 | (1)% | **835,905** | 840,173 | (1)% |
| Capital expenditures: | | | | | | |
| Exploration and development | **45,172** | 59,722 | (24)% | **164,492** | 289,029 | (43)% |
| Acquisitions, net of dispositions[3] | **11,037** | (2,074) | 632 % | **6,038** | (7,841) | 177 % |
| Corporate | **221** | 9 | 2,356 % | **760** | 557 | 36 % |
| Weighted average outstanding equivalent shares: (thousands)[1] | | | | | | |
| Basic | **260,047** | 256,386 | 1 % | **258,781** | 255,559 | 1 % |
| Diluted | **267,135** | 262,980 | 2 % | **265,671** | 262,046 | 1 % |

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Operating** | | | | | | |
| (boe conversion – 6:1 basis) | | | | | | |
| Production: | | | | | | |
| Natural gas (mmcf/day) | **281** | 318 | (12)% | **297** | 306 | (3)% |
| Natural gas liquids (bbls/day) | **19,131** | 19,284 | (1)% | **17,366** | 18,794 | (8)% |
| Oil (bbls/day)(4) | **2,108** | 2,463 | (14)% | **2,221** | 2,415 | (8)% |
| Total oil equivalent (boe/day) | **68,011** | 74,799 | (9)% | **69,154** | 72,156 | (4)% |
| Product prices:(5) | | | | | | |
| Natural gas ($/mcf) | **2.91** | 3.14 | (7)% | **2.78** | 3.05 | (9)% |
| Natural gas liquids ($/bbl) | **24.99** | 28.47 | (12)% | **29.30** | 27.29 | 7 % |
| Oil ($/bbl)(4) | **28.47** | 59.49 | (52)% | **53.07** | 57.80 | (8)% |
| Total oil equivalent ($/boe) | **19.91** | 22.65 | (12)% | **21.04** | 21.97 | (4)% |
| Operating expenses ($/boe) | **5.66** | 5.57 | 2 % | **5.70** | 5.59 | 2 % |
| Transportation expenses ($/boe) | **1.37** | 1.10 | 25 % | **1.34** | 0.94 | 43 % |
| General and administrative expenses ($/boe) | **0.87** | 0.99 | (12)% | **0.96** | 0.94 | 2 % |
| Cash costs ($/boe)(1) | **9.27** | 8.96 | 3 % | **9.39** | 8.92 | 5 % |
| Operating netback ($/boe)(1) | **11.99** | 14.81 | (19)% | **12.64** | 13.85 | (9)% |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(3) Expenditures on property acquisitions, net of property dispositions.
(4) Oil includes light, medium and heavy oil.
(5) Product prices include realized gains and losses on financial instrument commodity contracts.

## TWO CORE AREAS



The quality and predictability of Bonavista's asset portfolio, combined with the discipline and determination of its technical teams to innovate and deploy enhanced development practices has resulted in five percent growth in 2P reserves and a seven percent increase in our 2P BTNPV10.

Net capital expenditures[(1)] for 2018 were $171.3 million a 39% decrease from 2017 levels at $281.7 million. We remained committed to disciplined reinvestment levels, preserving cash flow from operating activities to allocate towards the reduction of our net debt[(1)]. Exploration and development expenditures were $164.5 million with $122.1 million allocated to drilling 24.9 net wells and completing 28.4 net wells. The remaining $42.4 million was spent on support capital, primarily crown land acquisitions and infrastructure enhancements. Our expenditures on acquisition, net of dispositions totaled $6.0 million, of which property acquisition comprised $32.7 million and property dispositions comprised $26.6 million.

## *Deep Basin Operations*

In 2018, 35% of exploration and development expenditures were invested in our Deep Basin core area. Of the $58 million total exploration and development expenditures in this area, $44 million was allocated to value capital and $14 million to support capital. During the year, we drilled 10 gross (7.1 net) wells mainly in the Wilrich, Notikewin, Falher and Bluesky formations.

Average 2018 production in our Deep Basin core area was 27,496 boe per day comprised of 88% natural gas. Although the oil and natural gas liquids production was only 12% of total Deep Basin production, it is predominately (approximately 70%) oil and condensate production.

In 2018, we completed the initial phase of our farm-in at Edson and tied in the majority of the production into our Ansell facility. The Edson area, northwest of Ansell, is an attractive multi-zone area with three prospective zones (Notikewin, Falher and Bluesky) successfully tested to-date. The Notikewin formation has been the most prolific with the first well having a peak monthly raw gas rate of 9.0 mmcf per day and averaging 6.5 mmcf per day over the first ten months of production. Our second Notikewin well was brought on in late December and is performing in a similar fashion in the first few weeks of production. At a well cost of $3.2 million to drill, complete, equip and tie-in, this play has an outstanding production efficiency of approximately $3,500 per boe per day.

The three well Bluesky program at Edson has averaged 3.3 mmcf per day per well over six months with a modest decline rate of only 11%. The value of these reliable Bluesky production profiles are enhanced with 18 barrels per mmcf of NGLs, 60% of which is condensate.

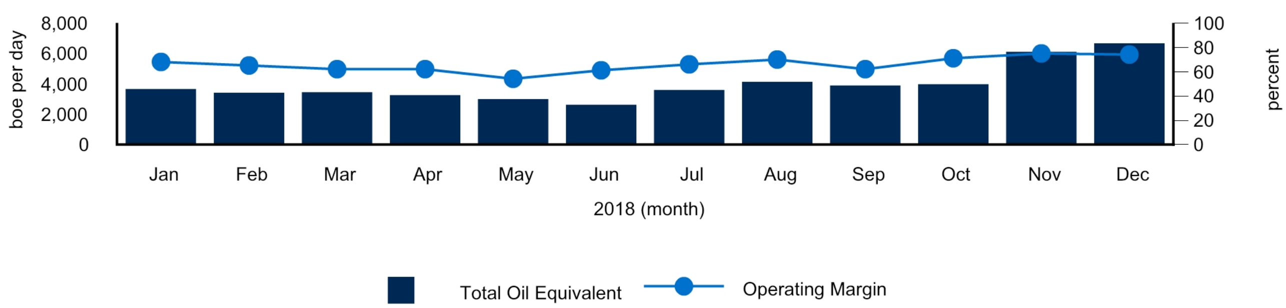
In the current low natural gas price environment, our 2018 Ansell Wilrich development was curtailed to the drilling of only three wells. The final two wells have just recently been brought on production.

## *West Central Operations*

In 2018, 61% of exploration and development expenditures were invested in our West Central core area. Of the $100 million total exploration and development expenditures in this area, $79 million was allocated to value capital and $21 million to support capital. During the year, we drilled, completed and placed on production 18 gross wells (17.8 net wells) comprised of 11 gross (10.8 net) Glauconite wells, six gross (6.0 net) Falher wells and one gross (1.0 net) Notikewin well. Average 2018 production in our West Central core area was 38,563 boe per day comprised of 41% oil and natural gas liquids.

The focus for development activity in West Central core area shifted to the Strachan area in 2018 where 44% of exploration and development expenditures were allocated. The drilling of six gross (5.8 net) wells resulted in the addition of 4,290 boe per day cumulatively, in the final month of 2018 which equates to a cost to add production of $7,640 per boe per day. This is a significant improvement over our 2017 program given that our cost per meter of lateral drilled has decreased by 24% from 2017 to 2018. Furthermore, targeting liquids rich areas of the reservoir resulted in our NGL ratio increasing 22% to 55 barrels per mmcf of raw gas, 40% of which is condensate. Lastly, the connection to the Ricinus facility in June has resulted in a reduction of natural gas shrinkage from 15% to 9%.

**Production and Performance Trend at Strachan**



The next most active area in West Central was our Morningside Falher play where we spent 24% of our exploration and development expenditures and drilled six gross (6.0 net) wells. The 2018 wells averaged 4.7 mmcf per day of raw gas per well over the first month of production which was a 31% improvement over our 2017 program. These results were heavily influenced by our drilling activity extending the play north of our historical development. The Morningside Falher play continues to demonstrate excellent metrics as the six well program resulted in cumulative production additions in the last month of 2018 of 3,430 boe per day for a production efficiency of $5,540 per boe per day.

Lastly, in the Hoadley Glauconite play our focus in 2018 was in Willesden Green, an area of the reservoir characterized with greater NGL content. The five gross (5.0 net) wells drilled in 2018 averaged 676 boe per day per well over the first three months of production, a 45% improvement over our 2017 program. The horizontal lateral length for the 2018 program was 17% longer with our well costs only four percent higher. The five well program resulted in production additions of 3,070 boe per day in the final month of 2018 generating a production efficiency of $5,530 per boe per day.

Section Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

(2) Reference in this section has been made to value capital, support capital and production efficiency. These terms do not have standardized meanings or standardized calculations and are not comparable to similar measures used by other entities. Reference should be made to the section entitled "Oil and Gas Advisories".

(3) Reference in this section has been made to initial production rates and other short-term production rates, Bonavista cautions that these rates are preliminary and not indicative of long term performance or of ultimate recovery. Reference should be made to the section entitled "Oil and Gas Advisories".

## YEAR-END RESERVES

The quality and predictability of our asset portfolio, combined with the discipline and determination of our technical teams to innovate and deploy enhanced development practices has resulted in five percent growth in 2P reserves and a seven percent increase in our 2P BTNPV10.

### 2018 Independent Reserves Evaluation

The evaluation of Bonavista's reserves was done in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). Additional reserves information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 31, 2019.

Bonavista retained the independent qualified reserve evaluators, GLJ Petroleum Consultants Ltd. (**"GLJ"**) to evaluate 100% of its total light crude oil and medium crude oil (combined), heavy crude oil, conventional natural gas and natural gas liquids reserves. The reserves data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2018 as contained in the reserve report of GLJ dated February 13, 2019 (the **"2018 GLJ Reserve Report"**). The 2018 GLJ Reserve Report used GLJ's forecast price and cost assumptions. The effective date of the forecast prices used in the 2018 GLJ Reserve Report was January 1, 2019.

The reserves data set forth below also contains information regarding Bonavista's 2017 reserve estimates which were based upon the evaluation by GLJ with an effective date of December 31, 2017 as contained in the reserve report of GLJ dated January 31, 2018 (the **"2017 GLJ Reserve Report"**). The 2017 GLJ Reserve Report used GLJ's forecast price and cost assumptions. The effective date of the forecast prices used in the 2017 GLJ Reserve Report was January 1, 2018.

The reserve estimates contained in the following tables represent Bonavista's gross reserves, unless otherwise specified, at December 31, 2018 and are defined under NI 51-101, as the Corporation's interest before deduction of royalties without including any of the Corporation's royalty interests. All future net revenues are estimated using forecast prices, arising from the anticipated development and production of Bonavista's reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis.

It should not be assumed that the present worth of estimated future net revenues presented in the tables below represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Bonavista's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Reference within this section has been made to the following oil and gas terms **"finding and development costs"** (**"F&D costs"**) and **"finding, development and acquisition costs"** (**"FD&A costs"**), **"F&D recycle ratio"**, **"FD&A recycle ratio"** and **"reserve life index"** (**"RLI"**) which have been prepared by management and do not have standardized meanings or standard calculations and therefore such measures may not be comparable to similar measures used by other entities. For further information on these terms, refer to the section "Oil and Gas Advisories".

All of Bonavista's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

### 2018 Reserves Highlights

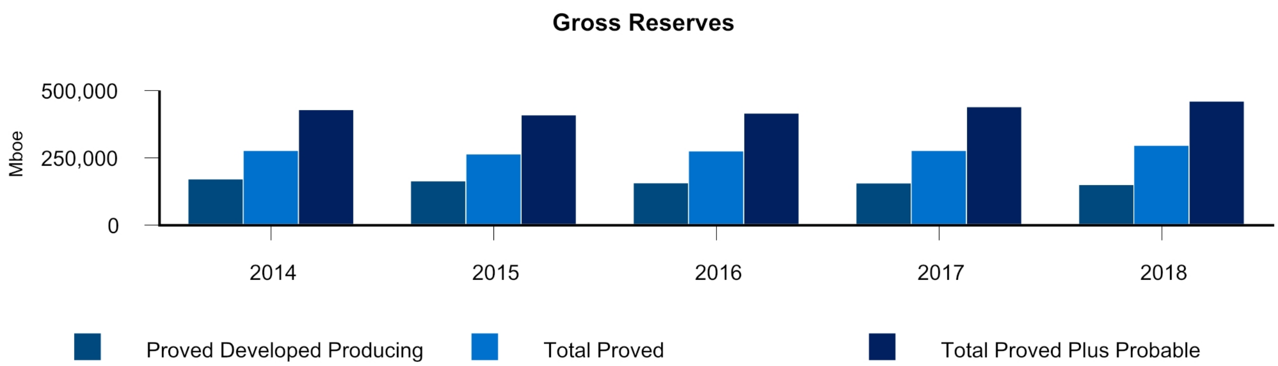
- Replaced 184% of 2018 production with the addition of 46.3 mmboe of 2P reserve additions. This was accomplished while spending less than 50% of our adjusted funds flow(1), with $128.1 million spent to drill 24.9 net wells and acquire reserves;
- Replaced 306% of 2018 NGL production with the addition of 19.4 mmboe of 2P NGL reserve additions. Our corporate 2P NGL ratio increased eight percent or 5 barrels per mmcf of sales gas resulting in 11% growth in 2P NGL reserves;
- 2P FD&A costs improved 24% to $5.72 per boe including changes in future development capital ("FDC") resulting in a 2P FD&A recycle ratio of 2.2:1;
- Proved producing FD&A improved year-over-year by 14% to $9.12 per boe including FDC with positive technical revisions of 1.1 mmboe, related primarily to NGL reserves, with continued well performance improvements;
- 2P F&D costs improved 11% to $6.78 per boe including FDC, a reserve addition cost last experienced by Bonavista 18 years ago;
- Continued innovation and the application of new technology has resulted in our average undeveloped well cost remaining at $3.5 million per well despite an increase of extended reach horizontal wells in our undeveloped inventory. This coupled with a five percent increase in the average 2P reserves per well has resulted in a decrease in our average forecasted undeveloped F&D costs of $5.98 per boe; and
- Notwithstanding a significant reduction in GLJ's price forecasts from year-end 2017 to 2018, our 2P BTNPV10 reserves increased seven percent to $2,635.1 million as at December 31, 2018. When adjusted for net debt(1) and undeveloped land value, our net asset value is $7.40 per share, an increase of eight percent or $0.58 per share compared to last year.

### *Reserves Summary*

The following table summarizes the estimates of Bonavista's gross reserves at December 31, 2018 and December 31, 2017, using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

| **Reserve Category**[(1)] | December 31, 2018 | December 31, 2017 | % Change |
|---|---|---|---|
| (Mboe) | | | |
| Proved: | | | |
| Developed Producing | **148,613** | 154,819 | (4)% |
| Developed Non-Producing | **9,057** | 7,658 | 18 % |
| Undeveloped | **136,506** | 112,531 | 21 % |
| Total Proved | **294,177** | 275,008 | 7 % |
| Probable | **164,704** | 162,735 | 1 % |
| Total Proved Plus Probable | **458,881** | 437,743 | 5 % |

Note:
(1) Amounts may not add due to rounding.




Notes:
(1) The reserve report prepared by GLJ dated February 3, 2015 and effective December 31, 2014
(2) The reserve report prepared by GLJ dated January 25, 2016 and effective December 31, 2015.
(3) The reserve report prepared by GLJ dated February 1, 2017 and effective December 31, 2016.
(4) The reserve report prepared by GLJ dated January 31, 2018 and effective December 31, 2017.
(5) The reserve report prepared by GLJ dated February 13, 2019 and effective December 31, 2018.

The following table sets forth Bonavista's crude oil, natural gas liquids and natural gas reserves at December 31, 2018, using GLJ's forecast price and cost assumptions:

| **Reserve Category**[(1)] | **Crude Oil**[(3)(4)] | | **Natural Gas**[(2)(4)] | | **Natural Gas Liquids**[(4)] | | **Total Reserves**[(4)] | |
|---|---|---|---|---|---|---|---|---|
| | Gross (Mbbls) | Net (Mbbls) | Gross (MMcf) | Net (MMcf) | Gross (Mbbls) | Net (Mbbls) | Gross (Mboe) | Net (Mboe) |
| Proved: | | | | | | | | |
| Developed Producing | 3,713 | 3,261 | 608,909 | 553,238 | 43,415 | 36,028 | 148,613 | 131,495 |
| Developed Non-Producing | 354 | 296 | 39,030 | 37,322 | 2,198 | 1,777 | 9,057 | 8,294 |
| Undeveloped | 682 | 612 | 573,649 | 524,379 | 40,215 | 35,200 | 136,506 | 123,207 |
| Total Proved | 4,749 | 4,168 | 1,221,589 | 1,114,939 | 85,829 | 73,005 | 294,177 | 262,996 |
| Probable | 2,216 | 1,863 | 717,873 | 650,779 | 42,842 | 35,987 | 164,704 | 146,313 |
| Total Proved Plus Probable | 6,966 | 6,031 | 1,939,462 | 1,765,718 | 128,671 | 108,991 | 458,881 | 409,309 |

Notes:
(1) Amounts may not add due to rounding.
(2) Includes conventional natural gas, shale natural gas and coal bed methane.
(3) Includes light, medium, heavy and tight oil.
(4) "Gross" means Bonavista's working interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests. "Net" means Bonavista's working interest (operating or non-operating) share after the deduction of royalty obligations, plus royalty interests in reserves. Bonavista's gross reserves for 2018 are based on the 2018 GLJ Reserve Report, dated February 13, 2019 effective December 31, 2018. GLJ reserve estimates were based on forecast prices and costs as of January 1, 2019.

### *Net Present Value of Future Net Revenue*

The following table highlights the net present value of future net revenue attributable to Bonavista's reserves at December 31, 2018, before deducting future income tax expense using GLJ's forecast price and cost assumptions:

| **Reserve Category**[1] | **Net Present Value of Future Net Revenue as of December 31, 2018 before Income Taxes Discounted at** | | | | | **Unit Value before Income Taxes Discounted at**[2] | |
|---|---|---|---|---|---|---|---|
| (%/year) | **0%** | **5%** | **10%** | **15%** | **20%** | **10%** | **10%** |
| | ($000s) | ($000s) | ($000s) | ($000s) | ($000s) | ($/boe) | ($/Mcfe) |
| Proved: | | | | | | | |
| Developed Producing | 1,877,187 | 1,450,682 | 1,173,200 | 984,874 | 850,805 | 8.92 | 1.49 |
| Developed Non-Producing | 60,569 | 48,397 | 38,785 | 31,530 | 26,031 | 4.68 | 0.78 |
| Undeveloped | 1,530,027 | 895,144 | 550,337 | 347,392 | 219,458 | 4.47 | 0.74 |
| Total Proved | 3,467,783 | 2,394,224 | 1,762,322 | 1,363,796 | 1,096,293 | 6.70 | 1.12 |
| Probable | 2,699,380 | 1,427,813 | 872,810 | 589,205 | 425,208 | 5.97 | 0.99 |
| Total Proved Plus Probable | 6,167,163 | 3,822,037 | 2,635,132 | 1,953,001 | 1,521,501 | 6.44 | 1.07 |

Notes:

(1) Amounts may not add due to rounding.
(2) Unit values are based on net reserves.

GLJ commodity price forecasts have been reduced significantly for most products relative to a year ago. For 2019, AECO natural gas prices have eroded 27% while the Edmonton light oil prices have been reduced by 10%. Similarly, for 2019 the ethane, propane, butane and pentane price has been reduced by 28%, 31%, 56% and 9% respectively. Bonavista's net present value of future net revenue attributable to Bonavista's 2P BTNPV10 increased seven percent to $2,635.1 million with a reserve life index of 16.6 years. The 505 2P undeveloped locations included in the 2018 GLJ Reserve Report have a BTNPV10 of $1.12 billion.

### *Pricing Assumptions*

The forecast price and cost assumptions used in Bonavista's reserves assume primarily an increase in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and foreign exchange rates used in the 2018 GLJ Reserve Report were as follows:

| Year | Edmonton Light Crude Oil | WTI Oil | AECO Gas | Foreign Exchange Rate |
|---|---|---|---|---|
| | (CDN$/bbl) | (US$/bbl) | (CDN$/MMBtu) | (US$/CDN$) |
| 2019 | 63.33 | 56.25 | 1.85 | 0.7500 |
| 2020 | 75.32 | 63.00 | 2.29 | 0.7700 |
| 2021 | 79.75 | 67.00 | 2.67 | 0.7900 |
| 2022 | 81.48 | 70.00 | 2.90 | 0.8100 |
| 2023 | 83.54 | 72.50 | 3.14 | 0.8200 |
| 2024 | 86.06 | 75.00 | 3.23 | 0.8250 |
| 2025 | 89.09 | 77.50 | 3.34 | 0.8250 |
| 2026 | 92.62 | 80.41 | 3.41 | 0.8250 |
| 2027 | 94.57 | 82.02 | 3.48 | 0.8250 |
| 2028 | 96.56 | 83.66 | 3.54 | 0.8250 |
| Thereafter | 2.0%/year | 2.0%/year | 2.0%/year | 0.8250 |

Note:

(1) GLJ's forecast commodity price report with an effective date January 1, 2019.

### *Reconciliation of Changes in Reserves*

The following table sets forth a reconciliation of Bonavista's gross reserves between December 31, 2018 and December 31, 2017 and using the forecast price and cost assumptions in effect at the applicable reserve evaluation date in the 2018 GLJ Reserve Report and 2017 GLJ Reserve Report:

| | RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS[1] | | | | |
|---|---|---|---|---|---|
| | **Light and Medium Crude** (Mbbls) | **Heavy Oil** (Mbbls) | **Natural Gas** (MMcf) | **Natural Gas Liquids** (Mbbls) | **Oil Equivalent** (Mboe) |
| **GROSS TOTAL PROVED** | | | | | |
| **December 31, 2017** | 5,962 | 400 | 1,155,012 | 76,145 | 275,008 |
| Extensions and Improved Recovery[2] | 158 | — | 131,242 | 9,617 | 31,649 |
| Technical Revisions[3] | (49) | (141) | 1,430 | 1,552 | 1,601 |
| Discoveries | — | — | — | — | — |
| Acquisitions | 81 | — | 50,534 | 5,244 | 13,748 |
| Dispositions | (990) | — | (4,181) | (232) | (1,919) |
| Economic Factors | 132 | 1 | (4,110) | (177) | (729) |
| Production | (790) | (15) | (108,339) | (6,321) | (25,182) |
| **December 31, 2018** | **4,504** | **245** | **1,221,589** | **85,829** | **294,177** |
| **GROSS TOTAL PROBABLE** | | | | | |
| **December 31, 2017** | 2,773 | 132 | 722,009 | 39,495 | 162,735 |
| Extensions and Improved Recovery[2] | 41 | — | 12,502 | 2,488 | 4,613 |
| Technical Revisions[3] | (315) | (34) | (27,016) | (517) | (5,369) |
| Discoveries | — | — | — | — | — |
| Acquisitions | 31 | — | 14,749 | 1,574 | 4,063 |
| Dispositions | (265) | — | (1,425) | (82) | (584) |
| Economic Factors | (145) | — | (2,947) | (115) | (752) |
| Production | — | — | — | — | — |
| **December 31, 2018** | **2,120** | **98** | **717,873** | **42,842** | **164,704** |
| **GROSS TOTAL PROVED PLUS PROBABLE** | | | | | |
| **December 31, 2017** | 8,735 | 532 | 1,877,021 | 115,640 | 437,743 |
| Extensions and Improved Recovery[2] | 198 | — | 143,744 | 12,105 | 36,261 |
| Technical Revisions[3] | (364) | (175) | (25,586) | 1,035 | (3,769) |
| Discoveries | — | — | — | — | — |
| Acquisitions | 112 | — | 65,283 | 6,818 | 17,811 |
| Dispositions | (1,255) | — | (5,605) | (314) | (2,503) |
| Economic Factors | (13) | 1 | (7,057) | (293) | (1,481) |
| Production | (790) | (15) | (108,339) | (6,321) | (25,182) |
| **December 31, 2018** | **6,623** | **343** | **1,939,462** | **128,671** | **458,881** |

Notes:

(1) Amounts may not add due to rounding.
(2) Infill drilling, improved recovery and extensions have been grouped as extensions and improved recovery as per NI 51-101.
(3) Includes product transfer types to reconcile the opening balance for changes in classification between light medium crude and heavy oil.

On average, 2018 2P reserve performance exceeded the projections in the 2017 GLJ Reserve Report as suggested by the following performance improvements:

- Added 1.1 mmboe of proved developed producing reserves due to positive technical revisions;
- Experienced a base production decline rate of 25% for 2018 versus the GLJ forecast at 28%;
- NGL production as a percentage of total production was similar to GLJ at 25% despite experiencing significant ethane curtailment at numerous times throughout 2018; and

- 2018 operating netback[1] of $12.64 per boe was approximately seven percent higher than that forecasted in the 2017 GLJ Reserve Report.

Of the 28 gross wells we drilled in 2018, 20 had been booked in the 2017 GLJ Reserve Report. Year-end 2018 2P reserves for these 20 wells amounted to 12.6 mmboe which modestly exceeded the forecast in the 2017 GLJ Reserve Report of 12.4 mmboe. Average 2P F&D costs for these 20 wells was $5.95 per boe, which was modestly higher than forecast resulting from minor operational challenges encountered with drilling and completing two wells in Strachan.

The quality and low risk nature of our future undeveloped reserves is evident with 64% of our booked undeveloped locations being categorized as proved undeveloped reserves, having a 90% or greater probability of achieving the estimated reserves by definition. Over 90% of our future proved plus probable locations exist in close proximity to our owned and operated infrastructure creating an efficient and effective solution to create value in the future.

### *Future Development Costs ("FDC")*

FDC reflects GLJ's best estimate of what it will cost to bring the proved and proved plus probable reserves on production. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates. The following table sets forth the schedule of FDC required to develop future reserves using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

| **Future Development Costs[1][2]** | **Total Proved** | **Total Proved plus Probable** |
|---|---|---|
| | ($ thousands) | ($ thousands) |
| 2019 | 116,333 | 143,739 |
| 2020 | 354,967 | 431,714 |
| 2021 | 295,751 | 356,900 |
| 2022 | 162,914 | 230,369 |
| 2023 | 102,727 | 287,720 |
| 2024 | 3,540 | 37,491 |
| 2025 | 669 | 2,921 |
| 2026 | 3,629 | 2,304 |
| 2027 | 472 | 1,705 |
| 2028 | 82 | 517 |
| 2029 | 205 | 2,251 |
| 2030 | 632 | 1,180 |
| Remaining | 8,566 | 10,838 |
| Total (Undiscounted) | 1,050,486 | 1,509,650 |
| Total (Discounted at 10%) | 842,040 | 1,173,778 |

Notes:

(1) Amounts may not add due to rounding.
(2) Future development costs include both developed and undeveloped reserves.

Total FDC, discounted at 10%, as a ratio of three-year trailing average adjusted funds flow[1][2] of $275.3 million is 4.3 times demonstrating our practical approach to booking future undeveloped reserves and our ability to sustainably fund the development of those future reserves.

### *Reserve Life Index ("RLI")*

Bonavista's business plan is to create premium shareholder value through the efficient development of high quality natural gas and oil assets. The profitable growth of Bonavista's reserves coupled with the sustainable production of these reserves will generate long-term returns for shareholders. In 2018, Bonavista's proved plus probable RLI increased by nine percent to 16.6 years demonstrating the long-term sustainable balance that exists between exploration and development expenditures, reserves additions and production levels.

The following table sets forth Bonavista's historical RLI:

| **Reserve Life Index (Years)[1]** | 2014 | 2015 | 2016 | 2017 | **2018** |
|---|---|---|---|---|---|
| Total Proved | 9.4 | 9.7 | 10.5 | 10.3 | **11.5** |
| Total Proved Plus Probable | 13.1 | 14.1 | 14.4 | 15.2 | **16.6** |

Note:

(1) Calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

### *Reserves Performance Ratios*

The following tables highlight Bonavista's gross reserves, F&D costs, FD&A costs and the associated recycle ratios for the trailing three years.

Bonavista considers recycle ratio an important measure of long-term profitability. It is measured by dividing the operating netback by the F&D costs per boe or FD&A costs for the year. Bonavista has delivered a three-year weighted average F&D recycle ratio of 1.9:1 and FD&A recycle ratio of 2.8:1 for proved plus probable reserves including revisions and changes in FDC.

| For the years ended December 31 | 2018 | 2017 | 2016 |
|---|---|---|---|
| **Reserves (Mboe):** | | | |
| Proved producing | **148,613** | 154,819 | 155,907 |
| Total proved | **294,177** | 275,008 | 273,183 |
| Proved plus probable | **458,881** | 437,743 | 414,205 |
| **Capital Expenditures ($ millions):** | | | |
| Exploration and development | **164.5** | 289.0 | 153.9 |
| Acquisitions, net of dispositions(4) | **6.0** | (7.8) | (167.9) |
| **Operating Netback ($/boe)(1):** | | | |
| Current year | **12.64** | 13.85 | 13.44 |
| Three-year weighted average | **13.32** | 14.55 | 17.54 |

**FINDING AND DEVELOPMENT COSTS**

| For the years ended December 31 | 2018 | 2017 | 2016 |
|---|---|---|---|
| **Proved Developed Producing:** | | | |
| Change in FDC ($ thousands) | **(1,822)** | (11,818) | (173) |
| Reserves additions (Mboe) | **16,368** | 25,902 | 15,831 |
| F&D costs ($/boe)(2) | **9.94** | 10.70 | 9.71 |
| F&D recycle ratio(3) | **1.3** | 1.3 | 1.4 |
| F&D three-year weighted costs ($/boe)(2) | **10.22** | 10.95 | 12.04 |
| F&D recycle ratio three-year weighted average(3) | **1.3** | 1.3 | 1.5 |
| **Total Proved:** | | | |
| Change in FDC ($ thousands) | **103,924** | (41,615) | 86,377 |
| Reserves additions (Mboe) | **32,521** | 28,237 | 26,972 |
| F&D costs ($/boe)(2) | **8.25** | 8.76 | 8.91 |
| F&D recycle ratio(3) | **1.5** | 1.6 | 1.5 |
| F&D three-year weighted costs ($/boe)(2) | **8.62** | 8.11 | 10.40 |
| F&D recycle ratio three-year weighted average(3) | **1.5** | 1.8 | 1.7 |
| **Total Proved plus Probable:** | | | |
| Change in FDC ($ thousands) | **45,850** | 75,423 | 60,902 |
| Reserves additions (Mboe) | **31,012** | 47,923 | 30,824 |
| F&D costs ($/boe)(2) | **6.78** | 7.60 | 6.97 |
| F&D recycle ratio(3) | **1.9** | 1.8 | 1.9 |
| F&D three-year weighted costs ($/boe)(2) | **7.19** | 7.34 | 9.11 |
| F&D recycle ratio three-year weighted average(3) | **1.9** | 2.0 | 1.9 |

**FINDING, DEVELOPMENT AND ACQUISITION COSTS**

| For the years ended December 31 | 2018 | 2017 | 2016 |
|---|---|---|---|
| **Proved Developed Producing:** | | | |
| Change in FDC ($ thousands) | **(1,822)** | (13,638) | (2,269) |
| Reserves additions (Mboe) | **18,493** | 25,182 | 18,879 |
| FD&A costs ($/boe)(2) | **9.12** | 10.62 | (0.86) |
| FD&A recycle ratio(3) | **1.4** | 1.3 | (15.6) |
| FD&A three-year weighted costs ($/boe)(2) | **6.71** | 8.22 | 9.69 |
| FD&A recycle ratio three-year weighted average(3) | **2.0** | 1.8 | 1.8 |
| **Total Proved:** | | | |
| Change in FDC ($ thousands) | **151,132** | (38,762) | 111,576 |
| Reserves additions (Mboe) | **44,350** | 28,095 | 36,004 |
| FD&A costs ($/boe)(2) | **7.25** | 8.63 | 2.71 |
| FD&A recycle ratio(3) | **1.7** | 1.6 | 5.0 |
| FD&A three-year weighted costs ($/boe)(2) | **6.10** | 5.50 | 7.81 |
| FD&A recycle ratio three-year weighted average(3) | **2.2** | 2.6 | 2.2 |
| **Total Proved plus Probable:** | | | |
| Change in FDC ($ thousands) | **94,511** | 95,119 | (3,821) |
| Reserves additions (Mboe) | **46,320** | 49,808 | 32,756 |
| FD&A costs ($/boe)(2) | **5.72** | 7.56 | (0.55) |
| FD&A recycle ratio(3) | **2.2** | 1.8 | (24.4) |
| FD&A three-year weighted costs ($/boe)(2) | **4.84** | 4.86 | 6.42 |
| FD&A recycle ratio three-year weighted average(3) | **2.8** | 3.0 | 2.7 |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. Reference should be made to the section entitled "Oil and Gas Advisories".
(3) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe. Reference should be made to the section entitled "Oil and Gas Advisories".
(4) Expenditures on property acquisitions, net of property dispositions.

Section Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures"
(2) References made to three-year trailing average adjusted funds flow is calculated by taking the average adjusted funds flow reported for the current period and two immediately preceding reporting periods.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## GENERAL

This Management's discussion and analysis (**"MD&A"**) for Bonavista Energy Corporation (the **"Corporation"** or **"Bonavista"**) is dated February 14, 2019. This MD&A with respect to the three months and year ended December 31, 2018 as compared to the three months and year ended December 31, 2017 has been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the audited consolidated financial statements (the **"financial statements"**) for the year ended December 31, 2018, together with the notes related thereto, for a full understanding of the financial position and results of operations of the Corporation.

The audited consolidated financial statements and comparative information for the year ended December 31, 2018 have been prepared in accordance with International Financial Reporting Standards (**"IFRS"**), as issued by the International Accounting Standard Board ("IASB"). All dollar amounts are presented in Canadian dollars (**"CDN"**), unless otherwise noted.

The MD&A refers to **"adjusted funds flow"**, **"operating netback"**, **"operating margin"**, **"cash costs"**, **"net capital expenditures"**, **"net debt"** and **"payout ratio"**, which do not have standardized meanings as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information, refer to the section "Non-GAAP Measures".

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, including the assumptions underlying such forward-looking information, refer to the "Forward-Looking Information" advisories section.

All boe amounts as presented in this MD&A have been calculated using the conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). For further information refer to the "Oil and Gas" advisories section.

## ABOUT BONAVISTA

Bonavista is a Canadian oil and natural gas producer headquartered in Calgary, Alberta. Bonavista's operations are concentrated to its Deep Basin and West Central core areas located in the Western Canadian Sedimentary Basin ("WCSB"). The Deep Basin core area is characterized by stacked, resource-rich reservoirs that are low in cost and provide high margin operations. The West Central core area draws its strength from a low-cost structure, extensive infrastructure and consistent well results often rich in natural gas liquids production. With two core areas Bonavista is structured to respond to changes in its business environment by having flexibility in how capital is allocated to create long-term value for its shareholders. Since inception, it has been Bonavista's priority to bring together the technical, operational and financial talent required to develop its high quality natural gas and oil assets in the most efficient and sustainable manner.

Bonavista's common shares are listed for trading on the Toronto Stock Exchange (the **"TSX"**) under the symbol **"BNP"**.

Additional information relating to Bonavista, including the Corporation's Annual Information Form, is available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

## 2019 GUIDANCE

Bonavista's Board of Directors has approved a net capital expenditures budget of between $130 and $170 million to generate annual average production of between 65,000 to 69,000 boe per day. Approximately $110 to $130 million will be allocated to exploration and development expenditures drilling 24 to 32 gross wells and between $20 and $40 million to support capital. This program will focus on liquids rich opportunities, but also allows for flexibility in capital allocation as supported by changing commodity prices.

Bonavista has budgeted for between $9 and $11 million of decommissioning expenditures for 2019 of which $2.3 million pertains to abandonment and reclamation projects where Bonavista is not the operator and $1.2 million for regulatory compliance projects. In addition, Bonavista expects to maintain its quarterly dividend policy of $0.01 per share. Together, this will generate adjusted funds flow of between $170 and $200 million and a payout ratio from 85% to 95% and allow for Bonavista to remain focused on net debt reduction in this commodity price environment. As in prior years, Bonavista will continue to monitor the economic landscape, commodity prices and our drilling results and adjust net capital expenditures as conditions warrant. The objective of Bonavista's 2019 net capital expenditure plan is to allocate capital to projects that will create sustaining value to shareholders by spending within adjusted funds flow while remaining opportunistic to changes in the commodity price environment.

The following table sets forth Bonavista's guidance and commodity price assumptions for 2019, as well as 2018 results for comparative purposes:

| | 2019 Guidance and Assumptions | 2018 Actual Results |
|---|---|---|
| Production: | | |
| Total oil equivalent (boe/day) | **65,000 - 69,000** | 69,154 |
| Natural gas (%) | **70%** | 72% |
| Natural gas liquids (%) | **27%** | 25% |
| Oil (%) | **3%** | 3% |
| Expenses ($/boe): | | |
| Royalties | **1.10 - 1.30** | 1.36 |
| Operating | **5.50 - 5.90** | 5.70 |
| Transportation | **1.30 - 1.50** | 1.34 |
| General and administrative | **0.80 - 1.20** | 0.96 |
| Interest | **1.20 - 1.60** | 1.39 |
| Net capital expenditures ($ thousands)(1): | | |
| Exploration and development | **130,000 - 170,000** | 164,492 |
| Acquisitions, net of dispositions, including corporate(2)(3) | **(4,000)** | 6,798 |
| Decommissioning expenditures ($ thousands) | **9,000 - 11,000** | 12,318 |
| Dividends declared ($ thousands) | **10,000 - 10,500** | 10,168 |
| Cash flow from operating activities ($ thousands) | **200,000 - 230,000** | 291,191 |
| Adjusted funds flow ($ thousands)(1) | **170,000 - 200,000** | 259,595 |
| Payout ratio (%)(1) | **85% - 95%** | 75% |
| Gross Wells (count) | **24 - 32** | 28 |
| Commodity Prices: | | |
| Average Edmonton light oil price ($/bbl) | **61.75** | 69.33 |
| Average AECO strip price ($/gj) | **1.54** | 1.44 |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) Expenditures on property acquisitions, net of property dispositions.
(3) Corporate capital expenditures refers to expenditures on office equipment.

Bonavista's 2018 results were largely in line with guidance. Production of 69,154 boe per day for the year ended December 31, 2018 fell within the guidance range of between 69,000 to 71,000 boe per day. Net capital expenditures of $171.3 million exceeded the high end of the guidance of between $155.0 to $165.0 million largely as a result of unbudgeted crown land purchases and fourth quarter acquisition activity. Cash flow from operating activities of $291.2 million exceeded the guidance of between $277.0 to $287.0 million. Adjusted funds flow of $259.6 million was at the midpoint of the guidance range of $255.0 to $265.0 million. Bonavista's payout ratio in 2018 was 75%, consistent with the high end of the guidance range of between 65% to 75%.

## SELECTED ANNUAL INFORMATION

| For the years ended December 31 | 2018 | 2017 | 2016 |
|---|---|---|---|
| ($ thousands, except per boe and per share amounts) | | | |
| Production revenues | **514,967** | 553,002 | 445,434 |
| Production: | | | |
| Natural gas (mmcf/day) | **297** | 306 | 280 |
| Natural gas liquids (bbls/day) | **17,366** | 18,794 | 18,247 |
| Oil (bbls/day)[4] | **2,221** | 2,415 | 3,708 |
| Total oil equivalent (boe/day) | **69,154** | 72,156 | 68,550 |
| Product prices:[5] | | | |
| Natural gas ($/mcf) | **2.78** | 3.05 | 3.13 |
| Natural gas liquids ($/bbl) | **29.30** | 27.29 | 19.97 |
| Oil ($/bbl)[4] | **53.07** | 57.80 | 61.89 |
| Total oil equivalent ($/boe) | **21.04** | 21.97 | 21.41 |
| Net income (loss) | **11,815** | (27,930) | (95,998) |
| Per share[1] | **0.05** | (0.11) | (0.40) |
| Cash flow from operating activities | **291,191** | 325,619 | 260,792 |
| Per share[1] | **1.13** | 1.27 | 1.10 |
| Adjusted funds flow[2] | **259,595** | 301,988 | 264,391 |
| Per share[1] | **1.00** | 1.18 | 1.11 |
| Operating netback ($/boe)[2] | **12.64** | 13.85 | 13.44 |
| Cash costs ($/boe)[2] | **9.39** | 8.92 | 9.40 |
| Operating expenses ($/boe) | **5.70** | 5.59 | 5.60 |
| General and administrative expenses ($/boe) | **0.96** | 0.94 | 1.08 |
| Net capital expenditures[2] | **171,290** | 281,745 | (13,430) |
| Total assets | **2,923,709** | 2,959,470 | 3,172,157 |
| Shareholders' equity | **1,552,184** | 1,539,461 | 1,560,244 |
| Long-term debt[3] | **801,625** | 800,544 | 930,221 |
| Net debt[2] | **835,905** | 840,173 | 877,523 |
| Weighted average outstanding equivalent shares: (thousands)[1] | | | |
| Basic | **258,781** | 255,559 | 237,806 |
| Diluted | **265,671** | 262,046 | 242,106 |
| Dividends declared | **10,168** | 10,040 | 13,891 |
| Per share | **0.04** | 0.04 | 0.06 |

Notes:

(1) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(2) Reference should be made to the section entitled "Non-GAAP Measures".
(3) Includes the current portion of long-term debt.
(4) Oil includes light, medium and heavy oil.
(5) Product prices include realized gains and losses on financial instrument commodity contracts.

## CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

The following table sets forth Bonavista's cash flow from operating activities and adjusted funds flow[1] for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, expert per share amounts) | | | | | | |
| Cash flow from operating activities | **77,581** | 94,515 | (18) % | **291,191** | 325,619 | (11) % |
| Per share[2] | **0.30** | 0.37 | (19) % | **1.13** | 1.27 | (11) % |
| Adjusted funds flow[1] | **61,075** | 86,108 | (29) % | **259,595** | 301,988 | (14) % |
| Per share[2] | **0.23** | 0.33 | (30) % | **1.00** | 1.18 | (15) % |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

(2) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

Details of the change in cash flow from operating activities for the three months and year ended December 31, 2017 to the three months and year ended December 31, 2018 are provided in the following table:

| | Three months ended December 31, | Year ended December 31, |
|---|---|---|
| ($ thousands) | | |
| Cash flow from operating activities - 2017 | 94,515 | 325,619 |
| Volume variance: | | |
| Natural gas | **(8,512)** | **(7,978)** |
| Natural gas liquids | **(485)** | **(15,820)** |
| Oil | **(2,033)** | **(4,027)** |
| Price variance: | | |
| Natural gas | **3,082** | **(50,466)** |
| Natural gas liquids | **(9,891)** | **35,508** |
| Oil | **(5,047)** | **4,748** |
| Realized gains on financial instrument commodity contracts | **(8,417)** | **(9,483)** |
| Royalties | **2,522** | **7,317** |
| Operating expenses | **2,960** | **3,230** |
| Transportation expenses | **(1,018)** | **(8,857)** |
| General and administrative expenses | **1,406** | **458** |
| Decommissioning expenditures | **3,548** | **5,000** |
| Working capital | **4,951** | **5,942** |
| **Cash flow from operating activities - 2018** | **77,581** | **291,191** |

For the year ended December 31, 2018, cash flow from operating activities decreased 11% to $291.2 million ($1.13 per share, basic) from $325.6 million ($1.27 per share, basic) for the same period of 2017. The decrease in cash flow from operating activities was primarily due to lower natural gas and natural gas liquids production volumes, lower natural gas prices, a decrease in realized gains on financial instrument commodity contracts and an increase in transportation expenses. The decrease was partially offset by higher natural gas liquids prices, lower royalties, a reduction in operating expenses, a decrease in decommissioning expenditures and an increase in working capital.

Cash flow from operating activities decreased 18% in the fourth quarter of 2018 to $77.6 million ($0.30 per share, basic) from $94.5 million ($0.37 per share, basic) generated in the fourth quarter of 2017. The decrease in cash flow from operating activities was primarily due to lower natural gas production volumes, lower natural gas liquids and oil prices and lower realized gains on financial instrument commodity contracts. The decrease was partially offset by lower royalties, a reduction in operating expenses, lower decommissioning expenditures and an increase in working capital.

For the year ended December 31, 2018, adjusted funds flow decreased 14% to $259.6 million ($1.00 per share, basic) from $302.0 million ($1.18 per share, basic) for the same period of 2017. The decrease in adjusted funds flow was primarily due to lower natural gas and natural gas liquids production volumes and lower natural gas prices, partially offset by an increase in natural gas liquids prices.

Adjusted funds flow decreased 29% in the fourth quarter of 2018 to $61.1 million ($0.23 per share, basic) from $86.1 million ($0.33 per share, basic) generated in the fourth quarter of 2017. The decrease in adjusted funds flow was primarily due to lower natural gas production volumes, lower natural gas liquids prices and lower realized gains on financial instrument commodity contracts.

## NET INCOME (LOSS)

The following table sets forth Bonavista's net income (loss) recognized for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, expert per share amounts) | | | | | | |
| Net income (loss) | **81,227** | (159,149) | 151 % | **11,815** | (27,930) | 142 % |
| Per share[1] | **0.31** | (0.62) | 150 % | **0.05** | (0.11) | 145 % |

Note:

(1) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

Details of the change in net loss for the three months and year ended December 31, 2017 to net income for three months and year ended December 31, 2018 are provided in the following table:

| | Three months ended December 31, | Year ended December 31, |
|---|---|---|
| ($ thousands) | | |
| Net loss - 2017 | (159,149) | (27,930) |
| Change in production revenues | **(22,886)** | **(38,035)** |
| Change in royalties | **2,522** | **7,317** |
| Change in realized gains on financial instrument commodity contracts | **(8,417)** | **(9,483)** |
| Change in unrealized gains on financial instrument commodity contracts | **149,028** | **(64,600)** |
| Change in operating expenses | **2,960** | **3,230** |
| Change in transportation expenses | **(1,018)** | **(8,857)** |
| Change in general and administrative expenses | **1,406** | **458** |
| Change in share-based compensation expenses | **882** | **5,321** |
| Change in gains (losses) on dispositions[1] | **(11,238)** | **(21,123)** |
| Change in depletion, depreciation, amortization and impairment | **224,337** | **242,108** |
| Change in net finance costs | **(6,231)** | **(45,241)** |
| Change in deferred income tax expense (recovery) | **(90,969)** | **(31,350)** |
| **Net income - 2018** | **81,227** | **11,815** |

Note:

(1) Includes the changes in gains and losses on the disposition of property, plant and equipment and exploration and evaluation assets.

Bonavista reported net income and comprehensive income of $11.8 million ($0.05 per share, basic) for the year ended December 31, 2018, compared to a net loss and comprehensive loss of $27.9 million ($0.11 per share, basic) reported during the same period of 2017. The net loss and comprehensive loss reported in the comparable prior period was largely due to a $215.0 million impairment charge that resulted from a sustained decline in natural gas commodity prices, changes in future development plans and technical reserve revisions. In 2018, indicators of impairment were also identified as a result of a sustained decline in natural gas commodity prices and impairment tests were conducted on each of Bonavista's CGUs. However, there was no impairment charge recorded as the recoverable amount was determined to exceed the carrying amount in each test. The impact of the impairment charge in 2017 was somewhat offset by changes in unrealized gains and losses on financial instrument commodity contracts and changes in unrealized gains and losses on foreign exchange, recorded within net finance costs, in relation to the revaluation of Bonavista's US denominated senior unsecured notes.

Bonavista recorded net income and comprehensive income of $81.2 million ($0.31 per share, basic) for the fourth quarter of 2018, compared to a net loss and comprehensive loss of $159.1 million ($0.62 per share, basic) for the fourth quarter of 2017. The change in net income (loss) between the fourth quarter of 2018 and 2017, was primarily due to the $215.0 million impairment charge recorded in the fourth quarter of 2017, changes in unrealized gains and losses on financial instrument commodity contracts and a change in Bonavista's deferred income tax provision. The significant change in unrealized gains and losses on financial instrument commodity contracts was caused by the continued volatility experienced in commodity markets throughout the three months ended December 31, 2018.

## DISCUSSION OF OPERATIONS

The following table sets forth Bonavista's drilling activity for the three months and year ended December 31:

| | Three months ended December 31, 2018 | | Year ended December 31, 2018 | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Wells drilled[1] | 5 | 4.3 | 28 | 24.9 |
| Wells completed[2] | 10 | 9.3 | 33 | 28.4 |
| Wells brought on production[3] | 10 | 9.3 | 33 | 28.4 |

Notes:

(1) Based on rig release date.
(2) Based on frac end date.
(3) Based on first production date tied-in to permanent facilities.

Consistent with Bonavista's asset concentration strategy, exploration and development activities in 2018 were focused on Bonavista's Deep Basin and West Central core areas. These two core areas, provide Bonavista with the agility to allocate capital to ensure the most economic plays are pursued in response to changes in commodity prices. This flexibility will be fundamental to Bonavista's capital program in 2019, as the Corporation remains focused on creating incremental financial flexibility by spending within adjusted funds flow.

Bonavista invested $45.2 million on exploration and development projects during the three months ended December 31, 2018, drilling one gross (1.0 net) liquids rich natural gas well in the West Central core area and four gross (3.3 net) liquids rich natural gas wells in the Deep Basin core area. Bonavista's exploration and development program of $164.5 million led to the drilling of 18 gross (17.8 net) wells in the West Central core area and 10 gross (7.1 net) wells in the Deep Basin core area for the year ended December 31, 2018. Development in the West Central core area was focused on Bonavista's most economic plays with 11 gross (10.8 net) Glauconite wells and seven gross (7.0 net) Spirit River (Falher and Notikewin) wells. The development in the Deep Basin core area was focused on high rate natural gas development and included eight gross (6.1 net) Spirit River (Wilrich, Falher, Notikewin and Ellerslie) wells, one gross (0.4 net) Bluesky well and one gross (0.6 net) Cardium well.

### *Production*

The following table sets forth Bonavista's production by product category for the three months and year ended December 31:

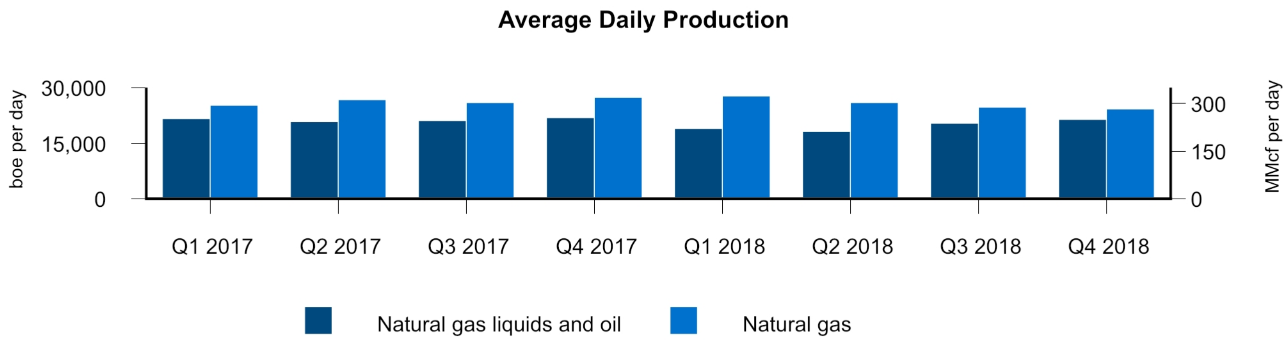
| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Natural gas (mmcf/day) | **281** | 318 | (12)% | **297** | 306 | (3)% |
| Natural gas liquids (bbls/day) | **19,131** | 19,284 | (1)% | **17,366** | 18,794 | (8)% |
| Oil (bbls/day) | **2,108** | 2,463 | (14)% | **2,221** | 2,415 | (8)% |
| Total oil equivalent (boe/day) | **68,011** | 74,799 | (9)% | **69,154** | 72,156 | (4)% |
| Natural gas liquids by component (bbls/day) | | | | | | |
| Ethane ($C_2$) | **7,094** | 6,785 | 5 % | **5,381** | 6,386 | (16)% |
| Propane ($C_3$) | **4,972** | 5,327 | (7)% | **5,048** | 5,311 | (5)% |
| Butane ($C_4$) | **2,840** | 2,868 | (1)% | **2,754** | 2,854 | (4)% |
| Pentanes plus and condensate ($C_{5+}$) | **4,225** | 4,304 | (2)% | **4,183** | 4,243 | (1)% |
| Natural gas liquids (bbls/day) | **19,131** | 19,284 | (1)% | **17,366** | 18,794 | (8)% |

Production volumes for the year ended December 31, 2018 averaged 69,154 boe per day, a four percent decrease compared to an average of 72,156 boe per day for the same period of 2017. The decrease in average production volumes over the comparable prior period resulted from natural production declines in excess of new well production growth combined with the impact arising from temporary production curtailments in response to low natural gas pricing which impacted average production volumes for the year by approximately 700 boe per day and an additional 1,400 boe per day from third party turnaround activities and ethane rejection.

For the year ended December 31, 2018, natural gas production averaged 297 mmcf per day, a three percent decrease compared to an average of 306 mmcf per day for the same period of 2017. The decrease in natural gas production was largely due to temporary shut-in of wells throughout the year in response to low natural gas prices. Natural gas liquids production was 17,366 bbls per day for the year ended December 31, 2018, an eight percent decrease when compared to 18,794 bbls per day for the same period of 2017. The decrease in natural gas liquids production largely resulted from a reduced exploration and development program in 2018 which led to natural production declines in excess of new well production growth in addition to temporary ethane production curtailments at two midstream facilities. The ethane curtailments had a negligible impact on Bonavista’s production revenues given that the heat value associated with the ethane remained in the residual natural gas stream enhancing the natural gas price. Oil production decreased eight percent to 2,221 bbls per day for the year ended December 31, 2018 from 2,415 bbls per day for the same period of 2017, due to natural production declines in mature light oil assets.

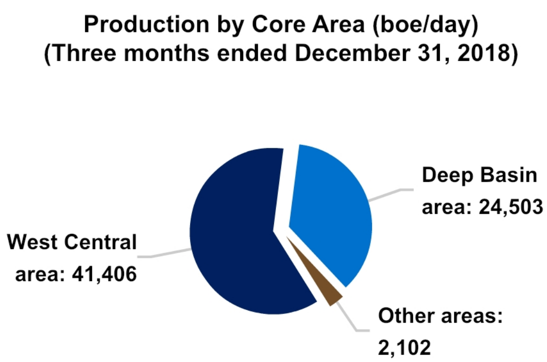
Production volumes for the three months ended December 31, 2018 averaged 68,011 boe per day, a nine percent decrease compared to an average of 74,799 boe per day for the same period of 2017. The decrease in average production volumes over the same prior year period resulted from natural production declines in excess of new well production growth due to a reduced exploration and development program in addition to the temporary production curtailments due to low natural gas pricing, third party processing constraints and ethane rejection which impacted fourth quarter average production volumes by approximately 1,600 boe per day.

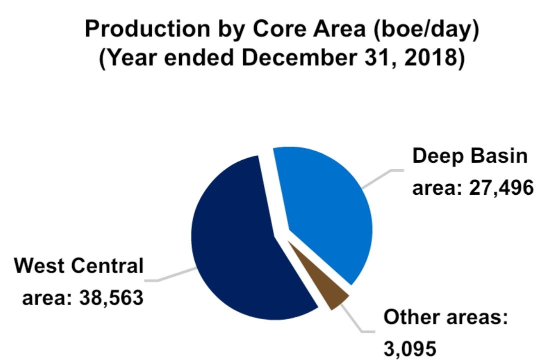
For the three months ended December 31, 2018, natural gas production averaged 281 mmcf per day, a 12% decrease compared to an average of 318 mmcf per day for the same period of 2017. Natural gas liquids production was 19,131 bbls per day for the three months ended December 31, 2018, a one percent decrease when compared to 19,284 bbls per day for the same period of 2017. The decrease in natural gas and natural gas liquids production was largely due to a reduction in new well production as a result of a curtailed exploration and development program. The decline in natural gas production volumes was exacerbated by low natural gas prices in the fourth quarter of 2018 which led to the temporary shut-in of natural gas volumes largely due to maintenance on the NGTL system and other third party interruptions. The decrease in natural gas liquids production volumes was somewhat mitigated by new well production growth from production brought-on during 2018 that was focused on liquids rich development in response to improved natural gas liquids prices. Oil production decreased 14% to 2,108 bbls per day for the three months ended December 31, 2018 compared to 2,463 bbls per day for the same period of 2017, due to natural production declines in mature light oil assets.




The following table sets forth Bonavista's production by product category and core area for the three months and year ended December 31:

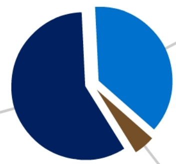
| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| West Central (boe/day) | **41,406** | 42,601 | (3)% | **38,563** | 41,929 | (8)% |
| Deep Basin (boe/day) | **24,503** | 28,672 | (15)% | **27,496** | 26,880 | 2 % |
| Other (boe/day) | **2,102** | 3,526 | (40)% | **3,095** | 3,347 | (8)% |
| Total oil equivalent (boe/day) | **68,011** | 74,799 | (9)% | **69,154** | 72,156 | (4)% |



Production by Core Area (boe/day)
(Three months ended December 31, 2017)


Production by Core Area (boe/day)
(Year ended December 31, 2017)




Bonavista's current production is approximately 67,000 to 68,000 boe per day, the composition of which is 70% natural gas and 30% natural gas liquids and oil.

### *Production revenues*

The following sets forth Bonavista's production revenues(1) by product category for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands) | | | | | | |
| Natural gas | **66,469** | 71,898 | (8)% | **236,333** | 294,777 | (20)% |
| Natural gas liquids | **50,813** | 61,189 | (17)% | **227,827** | 208,139 | 9 % |
| Oil | **7,020** | 14,101 | (50)% | **50,807** | 50,086 | 1 % |
| Total production revenues | **124,302** | 147,188 | (16)% | **514,967** | 553,002 | (7)% |
| **% of production revenue:** | | | | | | |
| Natural gas (%) | **53%** | 49% | 4 % | **46%** | 53% | (7)% |
| Natural gas liquids and oil (%) | **47%** | 51% | (4)% | **54%** | 47% | 7 % |

Note:

(1) Excludes the impact of financial instrument commodity contracts, but includes all fixed price physical contracts.

For the year ended December 31, 2018, production revenues, excluding the impact of financial instrument commodity contracts, decreased seven percent to $515.0 million compared to $553.0 million for the comparative period of 2017. The decrease was primarily due to a four percent decrease in average production volumes coupled with a three percent decrease in commodity prices on a per boe basis. The decrease in commodity prices was largely due to weaker natural gas prices at AECO as a result of Alberta's natural gas supply outpacing pipeline capacity takeaway expansions. The export capacity in Alberta was also impacted by significant maintenance on NOVA Gas Transmission Ltd. ("NGTL"). Offsetting the natural gas price decline was a year-over-year improvement of natural gas liquids and oil prices. Additionally, 23% of Bonavista's natural gas production has been physically diversified to US Midwest and Dawn markets, mitigating the impact of the continued weakness of natural gas prices at AECO in 2018 and beyond.

For the three months ended December 31, 2018, production revenues, excluding the impact of financial instrument commodity contracts, decreased 16% to $124.3 million compared to $147.2 million for the same period of 2017. The decrease was due to a nine percent decrease in average production volumes and a seven percent decrease in commodity prices on a per boe basis. In the fourth quarter of 2018 commodity prices were extremely volatile, with natural gas prices improving somewhat and natural gas liquids and oil prices eroding as a result of widening differentials in comparison to the fourth quarter of 2017.

### *Commodity Prices*

The following table outlines the average benchmark prices and exchange rates for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Average benchmark index prices: | | | | | | |
| Natural gas - AECO 5A daily index ($/gj) | **1.48** | 1.60 | (8)% | **1.42** | 2.04 | (30)% |
| Natural gas - AECO 7A monthly index ($/gj) | **1.80** | 1.85 | (3)% | **1.45** | 2.30 | (37)% |
| Natural gas - Ventura (daily) (US$/MMbtu) | **3.63** | 4.85 | (25)% | **2.96** | 3.32 | (11)% |
| Natural gas - Dawn (daily) (US$/MMbtu) | **3.79** | 2.93 | 29 % | **3.12** | 3.04 | 3 % |
| Light oil - MSW (Mixed Sweet) Edmonton ($/bbl) | **42.70** | 69.02 | (38)% | **70.92** | 62.84 | 13 % |
| CDN$/US$ exchange rate | **1.3215** | 1.2717 | 4 % | **1.2962** | 1.2979 | — % |

Canadian natural gas prices are mainly influenced by North American supply and demand fundamentals which can be impacted by a number of factors, including, but not limited to, weather-related conditions in key consuming natural gas markets, competition from alternative energy sources, changing demographics, economic growth or contraction, gas storage levels, net import and export markets, pipeline takeaway capacity, and drilling and completion rates and efficiencies in extracting natural gas from North American natural gas basins. AECO natural gas prices throughout the three months and year ended December 31, 2018 continued to receive a significant discount when compared to Chicago and Dawn benchmark prices, primarily due to an increase in Alberta's natural gas supply despite limited economic transportation and egress solutions out of the Western Canadian natural gas basins. To mitigate Bonavista's exposure to AECO pricing, Bonavista has engaged in an active market diversification strategy. Through this market diversification strategy Bonavista has entered into various gas marketing and transportation arrangements to diversify and gain exposure to alternative natural gas markets in North America.

Worldwide supply and demand factors are the primary determinant in the benchmark prices for crude oil; however, regional market and transportation issues also influence prices. Bonavista generally compares its oil price to the West Texas Intermediate (WTI) benchmark price, which is priced at Cushing, Oklahoma and the Mixed Sweet Blend (MSW) benchmark price, which is priced at Edmonton, Alberta. The differential between the WTI oil price and MSW price can widen due to a number of factors, including, but not limited to maintenance at North American refineries, domestic production, inventory levels and a lack of pipeline infrastructure connecting to key consuming oil markets. In the fourth quarter of 2018, the differentials widened further than normal with Canadian crude oil receiving much lower oil prices than under normal conditions. The primary factor behind these wide oil price differentials was a growing supply of western Canadian oil production with takeaway capacity remaining unchanged.

The following table sets forth Bonavista's physical and financial natural gas sales portfolio based on delivery point for the three months and year ended December 31, 2018:

| | Three months ended December 31, 2018 | Year ended December 31, 2018 |
|---|---|---|
| (% of natural gas production) | | |
| AECO physical spot price deliveries | 20% | 18% |
| AECO physical fixed and financial price sales contracts | 56% | 60% |
| Dawn physical deliveries | 14% | 13% |
| Midwest physical deliveries | 10% | 9% |

The following sets forth Bonavista's production revenues per boe, including realized gains and losses on financial instrument commodity contracts, for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Natural gas ($/mcf): | | | | | | |
| Production revenues[1] | **2.58** | 2.46 | 5 % | **2.18** | 2.64 | (17)% |
| Realized gains[2] | **0.33** | 0.68 | (51)% | **0.60** | 0.41 | 46 % |
| | **2.91** | 3.14 | (7)% | **2.78** | 3.05 | (9)% |
| Natural gas liquids ($/bbl): | | | | | | |
| Production revenues[1] | **28.87** | 34.49 | (16)% | **35.94** | 30.34 | 18 % |
| Realized losses[2] | **(3.88)** | (6.02) | (36)% | **(6.64)** | (3.05) | 118 % |
| | **24.99** | 28.47 | (12)% | **29.30** | 27.29 | 7 % |
| Oil ($/bbl): | | | | | | |
| Production revenues[1] | **36.21** | 62.24 | (42)% | **62.68** | 56.82 | 10 % |
| Realized gains (losses)[2] | **(7.74)** | (2.75) | 181 % | **(9.61)** | 0.98 | (1,081)% |
| | **28.47** | 59.49 | (52)% | **53.07** | 57.80 | (8)% |
| Total ($/boe): | | | | | | |
| Production revenues[1] | **19.87** | 21.39 | (7)% | **20.40** | 21.00 | (3)% |
| Realized gains[2] | **0.04** | 1.26 | (97)% | **0.64** | 0.97 | (34)% |
| | **19.91** | 22.65 | (12)% | **21.04** | 21.97 | (4)% |

Notes:

(1) Excludes the impact of financial instrument commodity contracts, but includes all fixed price physical contracts.
(2) Reference to realized gains (losses) on financial instrument commodity contracts.

Natural gas prices, excluding the impact of financial instrument commodity contracts, decreased 17% to $2.18 per mcf for the year ended December 31, 2018 compared to $2.64 per mcf for the same period of 2017. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, increased 18% to $35.94 per bbl for the year ended December 31, 2018 compared to $30.34 per bbl for the same period of 2017. Oil prices, excluding the impact of financial instrument commodity contracts, increased 10% to $62.68 per bbl for the year ended December 31, 2018 compared to $56.82 per bbl for the same period of 2017.

Natural gas prices, excluding the impact of financial instrument commodity contracts, increased five percent to $2.58 per mcf for the three months ended December 31, 2018 compared to $2.46 per mcf for the same period of 2017. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 16% to $28.87 per bbl for the three months ended December 31, 2018 compared to $34.49 per bbl for the same period of 2017. Oil prices, excluding the impact of financial instrument commodity contracts, decreased 42% to $36.21 per bbl for the three months ended December 31, 2018 compared to $62.24 per bbl for the same period of 2017.

Consistent with Bonavista's objectives to preserve financial flexibility and maintain a strong financial position through the management of its capital structure, financial instrument commodity contracts have partially mitigated Bonavista's exposure to the volatile commodity price environment. For the year ended December 31, 2018, a gain of $16.1 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $25.6 million in the same period of 2017. Similarly, for the three months ended December 31, 2018, a gain of $0.3 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $8.7 million in the same period of 2017.

Natural gas prices, including the impact of financial instrument commodity contracts, decreased nine percent to $2.78 per mcf for the year ended December 31, 2018 compared to $3.05 per mcf for the same period of 2017. Natural gas liquids prices, including the impact of financial instrument commodity contracts, increased seven percent to $29.30 per bbl for the year ended December 31, 2018 compared to $27.29 per bbl realized for the same period of 2017. Oil prices, including the impact of financial instrument commodity contracts, decreased eight percent to $53.07 per bbl for the year ended 2018 compared to $57.80 per bbl realized for the same period of 2017.

For the three months ended December 31, 2018, natural gas prices, including the impact of financial instrument commodity contracts, decreased seven percent to $2.91 per mcf compared to $3.14 per mcf for the same period of 2017. Natural gas liquids prices, including the impact of financial instrument commodity contracts, decreased 12% to $24.99 per bbl for the three months ended December 31, 2018 compared to $28.47 per bbl realized for the same period of 2017. Oil prices, including the impact of financial instrument commodity contracts, decreased 52% to $28.47 per bbl for the three months ended December 31, 2018 compared to $59.49 per bbl realized for the same period of 2017.

### *Risk management activities*

Bonavista has adopted a disciplined commodity price risk management program as part of its financial management strategy. Bonavista's risk management program aims to reduce the impact of commodity price volatility, protect adjusted funds flow to preserve financial flexibility, protect acquisition and development economics and fund dividend commitments. The Board of Directors has approved a commodity price risk management limit of 70% of forecasted revenues, net of royalties for the subsequent twelve month period, 60% in years two and three and 25% in years four and five, provided that no more than 80% of forecasted revenues, net of royalties, from any one product (where natural gas and ethane are considered as one product, propane is considered to be its own product and butane, condensate and oil are considered one product) may be hedged, or in the case of electricity, 60% of Bonavista's forecasted consumption. The term of any commodity hedge will be limited to no more than five calendar years subsequent to the current calendar year. Bonavista's Board of Directors regularly reviews this policy to reflect changes in market conditions.

### *Commodity price risk*

Commodity prices for natural gas, natural gas liquids and oil are impacted not only by global economic events that dictate the levels of supply and demand, but also by the relationship between the CDN and US currency. Swaps and costless collars are primarily entered into, which limits Bonavista's exposure to volatility in commodity prices while in the case of costless collars allows for the participation in some of the commodity price increases.

At December 31, 2018, Bonavista had entered into the following costless collars to sell oil and natural gas:

| Volume | | Average Price | Contract | Term |
|---|---|---|---|---|
| **Natural gas** | | | | |
| 15,000 | gjs/d | CDN $2.30 - CDN $2.77 | AECO - Costless Collar | January 1, 2019 - March 31, 2019 |
| **Oil contracts** | | | | |
| 500 | bbls/d | CDN $80.00 - CDN $93.00 | WTI - Costless Collar | January 1, 2019 - December 31, 2019 |
| 500 | bbls/d | CDN $67.50 - CDN $73.01 | WTI - Costless Collar | January 1, 2019 - December 31, 2020 |

At December 31, 2018, Bonavista had entered into the following contracts to manage its overall commodity exposure:

| Volume | | Price | Contract | Term |
|---|---|---|---|---|
| **Natural gas** | | | | |
| 5,000 | gjs/d | CDN $3.05 | AECO - Swap | January 1, 2019 - March 31, 2019 |
| 60,000 | gjs/d | CDN $1.98 | AECO - Swap | April 1, 2019 - June 30, 2019 |
| 70,000 | gjs/d | CDN $1.42 | AECO - Swap | April 1, 2019 - October 31, 2019 |
| 40,000 | gjs/d | CDN $2.15 | AECO - Swap | April 1, 2019 - December 31, 2019 |
| 10,000 | gjs/d | CDN $2.00 | AECO - Swap | November 1, 2019 - March 31, 2020 |
| 10,000 | mmbtu/d | US ($1.00) | AECO - Basis Swap | January 1, 2019 - December 31, 2019 |
| 10,000 | mmbtu/d | US ($0.98) | AECO - Basis Swap | January 1, 2020 - December 31, 2021 |
| 15,000 | mmbtu/d | US ($0.08) | DAWN - Basis Swap | January 1, 2019 - December 31, 2019 |
| 15,000 | mmbtu/d | US ($0.08) | DAWN - Basis Swap | January 1, 2019 - December 31, 2021 |
| 5,000 | mmbtu/d | US $5.15 | VENTURA - Swap | January 1, 2019 - March 31, 2019 |
| 50,000 | mmbtu/d | US $3.04 | NYMEX - Swap | January 1, 2019 - December 31, 2019 |
| 10,000 | gjs/d | CDN $2.75 | AECO - Sold Call | January 1, 2019 - December 31, 2019 |
| 20,000 | gjs/d | CDN $2.13 | AECO - Sold Call | November 1, 2019 - March 31, 2020 |
| 10,000 | gjs/d | CDN $1.75 | AECO - Sold Call | January 1, 2020 - December 31, 2020 |
| 10,000 | gjs/d | CDN $1.80 | AECO - Sold Call | January 1, 2021 - December 31, 2021 |
| 10,000 | mmbtu/d | US $4.40 | NYMEX - Sold Call | January 1, 2019 - March 31, 2019 |
| 20,000 | mmbtu/d | US $3.02 | NYMEX - Sold Call | January 1, 2019 - December 31, 2019 |
| 10,000 | mmbtu/d | US $3.75 | NYMEX - Sold Call | January 1, 2019 - December 31, 2021 |
| **Natural gas liquids** | | | | |
| 2,250 | bbls/d | US $33.18 | MTB BT - Swap | January 1, 2019 - December 31, 2019 |
| 1,200 | bbls/d | US $34.27 | MTB BT - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | US $35.75 | CNWY PN - Swap | January 1, 2019 - March 31, 2019 |
| 3,500 | bbls/d | US $26.84 | CNWY PN - Swap | January 1, 2019 - December 31, 2019 |
| 1,750 | bbls/d | US $28.59 | CNWY PN - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | US $26.04 | CNWY PN - Swap | January 1, 2020 - March 31, 2020 |
| **Oil** | | | | |
| 3,250 | bbls/d | CDN $72.28 | WTI - Swap | January 1, 2019 - December 31, 2019 |
| 750 | bbls/d | CDN $81.89 | WTI - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | CDN $80.17 | WTI - Swap | January 1, 2021 - December 31, 2021 |
| 1,000 | bbls/d | CDN $90.00 | WTI - Sold Call | January 1, 2020 - December 31, 2020 |
| 1,000 | bbls/d | US $54.60 | WTI - Sold Call | January 1, 2020 - December 31, 2020 |

Subsequent to December 31, 2018, Bonavista entered into the following contracts to manage its overall commodity exposure:

| Volume | | Price | Contract | Term |
|---|---|---|---|---|
| 27,500 | gjs/d | CDN $1.23 | AECO - Swap | April 1, 2019 - October 31, 2019 |
| 250 | bbls/d | US ($8.75) | MSW - Basis | March 1, 2019 - December 31, 2019 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2020 - October 31, 2020 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2021 - October 31, 2021 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2022 - October 31, 2022 |
| 20,000 | mmbtu/d | US ($0.16) | CHICAGO - Basis Swap | April 1, 2022 - October 31, 2022 |

At December 31, 2018, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $69.2 million compared to a net asset of $26.2 million at December 31, 2017. Of the $69.2 million net asset balance at December 31, 2018, a net asset of $54.5 million relates to financial instrument commodity contracts with term dates within one year and a net asset of $14.7 million relates to financial instrument commodity contracts with term dates beyond one year.

For the year ended December 31, 2018, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net gain of $59.1 million, consisting of a realized gain of $16.1 million and an unrealized gain of $43.0 million. The realized gain of $16.1 million consisted of a $66.0 million gain on natural gas commodity derivative contracts, a $42.1 million loss on natural gas liquids commodity derivative contracts and a $7.8 million loss on oil commodity derivative contracts. For the same period of 2017, the financial instrument commodity contracts in place resulted in a net gain of $133.2 million, consisting of a realized gain of $25.6 million and an unrealized gain of $107.6 million. The realized gain of $25.6 million consisted of a $45.7 million gain on natural gas commodity derivative contracts, a $21.0 million loss on natural gas liquids commodity derivative contracts and a $0.9 million gain on oil commodity derivative contracts.

For the three months ended December 31, 2018, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net gain of $140.1 million, consisting of a realized gain of $0.3 million and an unrealized gain of $139.8 million. The realized gain of $0.3 million consisted of an $8.6 million gain on natural gas commodity derivative contracts, a $6.8 million loss on natural gas liquids commodity derivative contracts and a $1.5 million loss on oil commodity derivative contracts. For the same period of 2017, the financial instrument commodity contracts in place resulted in a net loss of $0.5 million, consisting of a realized gain of $8.7 million and an unrealized loss of $9.2 million. The realized gain of $8.7 million consisted of a $20.0 million gain on natural gas commodity derivative contracts, a $10.7 million loss on natural gas liquids commodity derivative contracts and a $0.6 million loss on oil commodity derivative contracts.

The following table sets forth Bonavista's realized and unrealized gains and losses on financial instrument commodity contracts for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands) | | | | |
| Natural gas | **8,603** | 19,995 | **65,977** | 45,660 |
| Natural gas liquids | **(6,835)** | (10,688) | **(42,104)** | (20,951) |
| Oil | **(1,500)** | (622) | **(7,790)** | 857 |
| Realized gains on financial instrument commodity contracts | **268** | 8,685 | **16,083** | 25,566 |
| Unrealized gains (losses) on financial instrument commodity contracts | **139,841** | (9,187) | **43,014** | 107,614 |
| Net gain (loss) on financial instrument commodity contracts | **140,109** | (502) | **59,097** | 133,180 |

Bonavista's financial instrument commodity contracts are sensitive to commodity price volatility. The following tables highlight the approximate impact that changes in the fair value of the financial instrument commodity contracts would have on net income at December 31, 2018 with changes to the underlying commodity prices.

| | **Commodity Price Sensitivity** | |
|---|---|---|
| ($ thousands) | | |
| | Increase $0.10 | Decrease $0.10 |
| Natural Gas Commodity Contracts | (6,391) | 6,391 |
| | Increase $1.00 | Decrease $1.00 |
| Natural Gas Liquids Commodity Contracts | (3,242) | 3,242 |
| | Increase $1.00 | Decrease $1.00 |
| Oil Commodity Contracts | (1,461) | 1,461 |

In addition to these financial instrument commodity contracts in place, Bonavista had also entered into the following fixed price physical contract to sell natural gas as at December 31, 2018:

| **Volume** | | **Price** | **Term** |
|---|---|---|---|
| 20,000 | gjs/d | CDN $2.25 | November 1, 2019 - March 31, 2020[1] |

Note:

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 20,000 gjs/d on the last trade date of each month for the duration of the contract.

### *Foreign exchange risk*

Bonavista is exposed to foreign currency fluctuations as natural gas, natural gas liquids and oil prices received are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar natural gas, natural gas liquids and oil swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate.

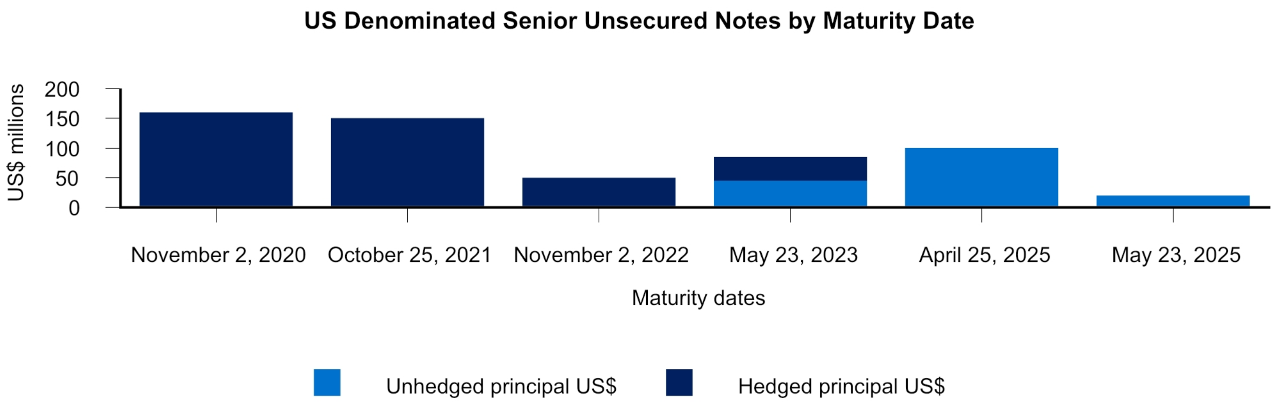
To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments:

| Settlement date | Contract | Notional US$ | CDN$/US$ |
|---|---|---|---|
| 2019[(1)] | US$ purchased forward | $9,314,400 | 1.2288 |
| November 2, 2020 | US$ purchased forward | $160,000,000 | 1.3049 |
| October 25, 2021 | US$ purchased forward | $150,000,000 | 1.2991 |
| November 2, 2022 | US$ purchased forward | $50,000,000 | 1.3012 |
| May 23, 2023 | US$ purchased forward | $40,000,000 | 1.2974 |

Note:

(1) Settlement dates of varying notional amounts coincide with interest payments on US dollar denominated senior unsecured notes, including: April 25, May 2, May 23, October 25, November 2 and November 23 of 2019.

Below is an illustration of the notional amount of Bonavista's foreign exchange contracts as compared to the principal repayment of its US denominated senior unsecured notes at maturity:




The fair value recorded on the consolidated statement of financial position for these financial instrument contracts at December 31, 2018 was a net asset of $18.4 million, of which a net asset of $1.2 million relates to financial instrument contracts with term dates within one year and a net asset of $17.2 million related to financial instrument contracts with term dates beyond one year. In comparison the fair value of those instruments in place at December 31, 2017 was a net liability of $19.3 million all of which related to financial instrument contracts with term dates beyond one year.

For the year ended December 31, 2018, an unrealized gain on financial instrument contracts of $37.7 million was recorded, compared to an unrealized loss of $23.7 million for the same period of 2017. The unrealized gain for the year ended December 31, 2018, resulted from the weakening of the CDN dollar relative to the US dollar, which at December 31, 2018 was $1.3641 CDN$/US$ compared to the December 31, 2017 rate of $1.2573 CDN$/US$. For the three months ended December 31, 2018, an unrealized gain of $28.5 million was recorded, compared to an unrealized gain of $6.6 million for the same period of 2017. The unrealized gain for the three months ended December 31, 2018, resulted from a weaker CDN dollar relative to the US dollar, which at December 31, 2018 was $1.3641 CDN$/US$ compared to the September 30, 2018 rate of $1.2911 CDN$/US$.

Bonavista's financial instrument contracts are sensitive to changes in the CDN dollar to the US dollar exchange rate. Holding all other variables constant, a $0.01 change in the CDN$/US$ exchange rate at December 31, 2018 would have had an impact of approximately $3.5 million on net income.

### *Royalties*

The following table sets forth Bonavista's royalties[1] by product category for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Natural gas ($/mcf): | | | | | | |
| Royalties | **(0.17)** | (0.14) | (21)% | **(0.12)** | — | (100)% |
| % of Production revenues[2] | **(6.5)%** | (5.8)% | (0.7)% | **(5.5)%** | (0.2)% | (5.3)% |
| Natural gas liquids ($/bbl): | | | | | | |
| Royalties | **5.05** | 6.13 | (18)% | **6.47** | 5.31 | 22 % |
| % of Production revenues[2] | **17.5 %** | 17.8 % | (0.3)% | **18.0 %** | 17.5 % | 0.5 % |
| Oil ($/bbl): | | | | | | |
| Royalties | **4.96** | 5.87 | (16)% | **7.90** | 6.51 | 21 % |
| % of Production revenues[2] | **13.7 %** | 9.4 % | 4.3 % | **12.6 %** | 11.5 % | 1.1 % |
| Total: | | | | | | |
| Royalties ($ thousands) | **5,544** | 8,066 | (31)% | **34,360** | 41,677 | (18)% |
| Royalties ($/boe) | **0.89** | 1.17 | (24)% | **1.36** | 1.58 | (14)% |
| % of Production revenues[2] | **4.5 %** | 5.5 % | (1.0)% | **6.7 %** | 7.5 % | (0.8)% |

Notes:

(1) Bonavista's royalty obligations are primarily with the Government of Alberta.
(2) % of production revenues excludes realized gains and losses on financial instrument commodity contracts.

Royalties for the year ended December 31, 2018 decreased 18% to $34.4 million from $41.7 million for the same period of 2017. Royalties as a percentage of total production revenues were 6.7% for the year ended December 31, 2018 compared to 7.5% for the year ended December 31, 2017. The decrease in royalties on an absolute basis and as a percentage of production revenues for the year ended December 31, 2018, was due to a one-time natural gas crown royalty allowable cost adjustment of $5.1 million in addition to a seven percent decrease in production revenues.

Natural gas royalties as a percentage of natural gas production revenues for the year ended December 31, 2018 was a recovery of 5.5% compared to a recovery of 0.2% for the year ended December 31, 2017, due to prior period natural gas crown royalty allowable cost adjustments. In addition, stronger realized prices in comparison to crown reference prices resulted in further reductions to natural gas royalties as a percentage of production revenues. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the year ended December 31, 2018 were 18.0% compared to 17.5% for the same period of 2017. Natural gas liquids royalties were higher as a percentage of production revenues, due to a change in the composition of Bonavista's natural gas liquids production revenues. This resulted in a higher propane, butane and condensate revenue weighting leading to a higher overall royalty rate. Oil royalties as a percentage of oil production revenues for the year ended December 31, 2018 were 12.6% compared to 11.5% for the year ended December 31, 2017.

For the three months ended December 31, 2018 royalties decreased 31% to $5.5 million from $8.1 million for the same period of 2017. Royalties as a percentage of total production revenues were 4.5% for the three months ended December 31, 2018 compared to 5.5% for the three months ended December 31, 2017. The decrease in royalties as a percentage of production revenues for the three months ended December 31, 2018, was due primarily to natural gas crown royalty allowable cost adjustments.

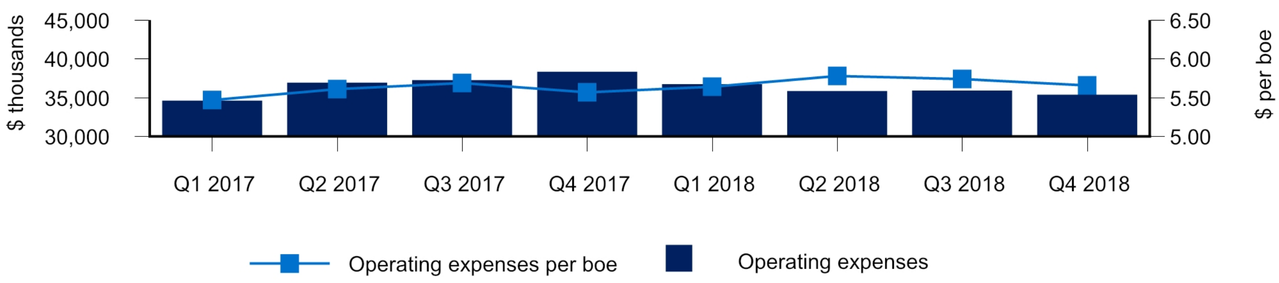
Natural gas royalties as a percentage of natural gas production revenues for the three months ended December 31, 2018 was a recovery of 6.5% compared to a recovery of 5.8% for the three months ended December 31, 2017, for similar reasons as noted above. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the three months ended December 31, 2018 were 17.5% compared to 17.8% for the same period of 2017. Oil royalties as a percentage of oil production revenues for the three months ended December 31, 2018 were 13.7% compared to 9.4% for the three months ended December 31, 2017. Oil royalties in the fourth quarter of 2017 were impacted by prior period crown royalty adjustments.

### *Operating expenses*

The following sets forth Bonavista's operating expenses for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe amounts) | | | | | | |
| Operating expenses | **35,383** | 38,343 | (8)% | **143,935** | 147,165 | (2)% |
| Per boe | **5.66** | 5.57 | 2 % | **5.70** | 5.59 | 2 % |

**Operating Expenses**




For the year ended December 31, 2018, operating expenses decreased two percent to $143.9 million compared to $147.2 million for the same period of 2017, primarily as a result of a four percent decrease in production volumes. On a per boe basis, operating expenses increased two percent to $5.70 per boe for the year ended December 31, 2018 compared to $5.59 per boe for the year ended December 31, 2017. The slight increase in operating expenses on a per boe basis was largely due to the temporary shut-in of wells in response to low natural gas prices, third party turnaround activities and ethane rejection, partially offset by development focused on core assets with low cost structures. These production curtailments impact operating expenses on a per boe basis as fixed costs are spread amongst fewer producing barrels of oil equivalent.

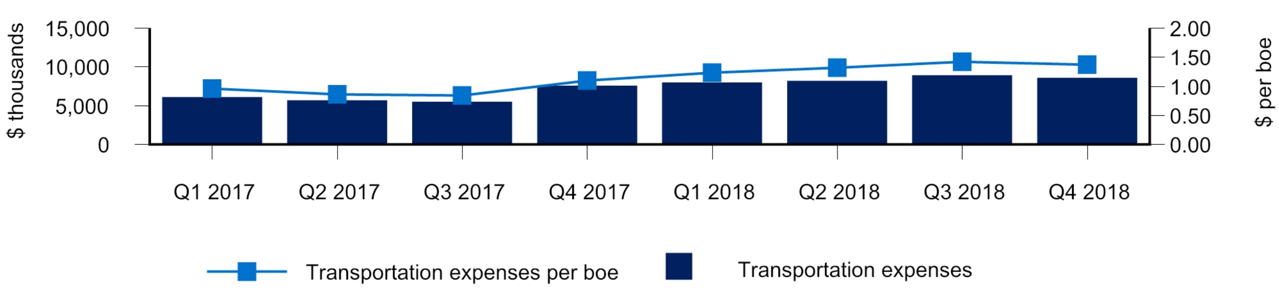
For the three months ended December 31, 2018, operating expenses decreased eight percent to $35.4 million compared to $38.3 million for the same period of 2017, primarily as a result of a nine percent decrease in production volumes. On a per boe basis, operating expenses increased two percent to $5.66 per boe for the three months ended December 31, 2018 compared to $5.57 per boe for the same period of 2017. The slight increase in operating expenses on a per boe basis, was due to the impact of the temporary shut-in of wells in response to low natural gas pricing.

### *Transportation expenses*

The following table sets forth Bonavista's transportation expenses for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe, per bbl, and per mcf amounts) | | | | | | |
| Transportation expenses | **8,602** | 7,584 | 13 % | **33,728** | 24,871 | 36 % |
| Per boe | **1.37** | 1.10 | 25 % | **1.34** | 0.94 | 43 % |
| Natural gas ($/mcf) | **0.30** | 0.23 | 30 % | **0.28** | 0.19 | 47 % |
| Natural gas liquids ($/bbl) | **0.45** | 0.36 | 25 % | **0.44** | 0.42 | 5 % |
| Oil ($/bbl) | **0.74** | 0.87 | (15)% | **0.76** | 0.88 | (14)% |

**Transportation Expenses**




Transportation expenses for the year ended December 31, 2018, increased 36% to $33.7 million compared to $24.9 million for the same period of 2017. On a per boe basis, transportation expenses for the year ended December 31, 2018 increased 43% to $1.34 per boe from $0.94 per boe for the comparable period of 2017. Similarly, transportation expenses for the three months ended December 31, 2018, increased 13% to $8.6 million compared to $7.6 million for the same period of 2017. On a per boe basis, transportation expenses for the three months ended December 31, 2018 increased 25% to $1.37 per boe from $1.10 per boe for the comparable period of 2017.

The increase in transportation on an absolute and per boe basis for both the three months and year ended December 31, 2018 was impacted by a 10-year contract with TransCanada for Long Term Fixed Price ("LTFP") service and the corresponding NGTL firm delivery service, to transport natural gas on TransCanada's Mainline pipeline from Alberta to the Dawn market in Southern Ontario to diversify Bonavista's natural gas delivery points beyond AECO. Service under this contract commenced on November 1, 2017. To a lesser extent transportation expenses for natural gas were also impacted by unutilized firm service costs as a result of the temporary curtailment of production in response to low natural gas pricing in part due to significant NGTL maintenance. Transportation expenses for natural gas liquids were impacted by changes made to contract terms including custody transfer points, effective for the new contract year commencing April 1, 2018.

With ongoing concerns over transportation constraints, Bonavista has secured firm transportation capacity to support current development plans, with firm transportation on the NGTL system.

### *Operating Netback and Operating Margin*

The following tables set forth Bonavista's operating netback[(1)] per boe and operating margin[(1)] by core area for the three months and year ended December 31:

| | Three months ended December 31, 2018 | | | Three months ended December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | West Central | Deep Basin | Total[(3)] | West Central | Deep Basin | Total[(3)] |
| ($ per boe) | | | | | | |
| Production revenues | **20.22** | **19.90** | **19.87** | 23.19 | 20.34 | 21.39 |
| Realized gains on financial instrument commodity contracts[(2)] | **—** | **—** | **0.04** | — | — | 1.26 |
| | **20.22** | **19.90** | **19.91** | 23.19 | 20.34 | 22.65 |
| Royalties | **1.27** | **0.48** | **0.89** | 1.55 | 0.72 | 1.17 |
| Operating expense | **5.82** | **4.34** | **5.66** | 5.92 | 4.41 | 5.57 |
| Transportation expense | **0.95** | **2.15** | **1.37** | 0.80 | 1.61 | 1.10 |
| Operating netback | **12.18** | **12.93** | **11.99** | 14.92 | 13.60 | 14.81 |
| Operating margin | **60%** | **65%** | **60%** | 64% | 67% | 65% |

| | Year ended December 31, 2018 | | | Year ended December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | West Central | Deep Basin | Total[(3)] | West Central | Deep Basin | Total[(3)] |
| ($ per boe) | | | | | | |
| Production revenues | **21.94** | **19.00** | **20.40** | 21.93 | 20.47 | 21.00 |
| Realized gains on financial instrument commodity contracts[(2)] | **—** | **—** | **0.64** | — | — | 0.97 |
| | **21.94** | **19.00** | **21.04** | 21.93 | 20.47 | 21.97 |
| Royalties | **1.86** | **0.78** | **1.36** | 1.99 | 1.12 | 1.58 |
| Operating expense | **6.30** | **4.01** | **5.70** | 5.82 | 4.47 | 5.59 |
| Transportation expense | **0.99** | **1.91** | **1.34** | 0.68 | 1.40 | 0.94 |
| Operating netback | **12.79** | **12.30** | **12.64** | 13.44 | 13.48 | 13.85 |
| Operating margin | **58%** | **65%** | **60%** | 61% | 66% | 63% |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP Measures".
(2) Amounts are not allocated by area.
(3) Total includes amounts recorded in the British Columbia area that are not inclusive in the West Central and Deep Basin core areas.

Bonavista's operating netback for the year ended December 31, 2018, decreased nine percent to $12.64 per boe compared to $13.85 per boe for the same period of 2017. The decrease in Bonavista's operating netback on a per boe basis was largely due to a 43% increase in transportation expenses and a four percent decrease in commodity pricing (including realized gains on financial instrument commodity contracts), partially offset by a 14% decrease in royalty expenses on a per boe basis. Bonavista's operating margin declined to 60% for the year ended December 31, 2018 compared to 63% for the year ended December 31, 2017, for the reasons noted above.

Bonavista's operating netback for the three months ended December 31, 2018, decreased 19% to $11.99 per boe compared to $14.81 per boe for the same period of 2017. The decrease in Bonavista's operating netback on a per boe basis was primarily due to a 12% decrease in commodity pricing (including realized gains on financial instrument commodity contracts). Bonavista's operating margin also declined to 60% for the three months ended December 31, 2018 compared to 65% for the three months ended December 31, 2017, primarily as result of the decrease in commodity pricing (including realized gains on financial instrument commodity contracts).

### *Cash Costs*

The following table sets forth Bonavista's cash costs[1] on a per boe basis for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ per boe) | | | | | | |
| Operating expenses | **5.66** | 5.57 | 2 % | **5.70** | 5.59 | 2 % |
| Transportation expenses | **1.37** | 1.10 | 25 % | **1.34** | 0.94 | 43 % |
| General and administrative expenses | **0.87** | 0.99 | (12)% | **0.96** | 0.94 | 2 % |
| Interest expense | **1.37** | 1.30 | 5 % | **1.39** | 1.45 | (4)% |
| Cash costs | **9.27** | 8.96 | 3 % | **9.39** | 8.92 | 5 % |

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP Measures".

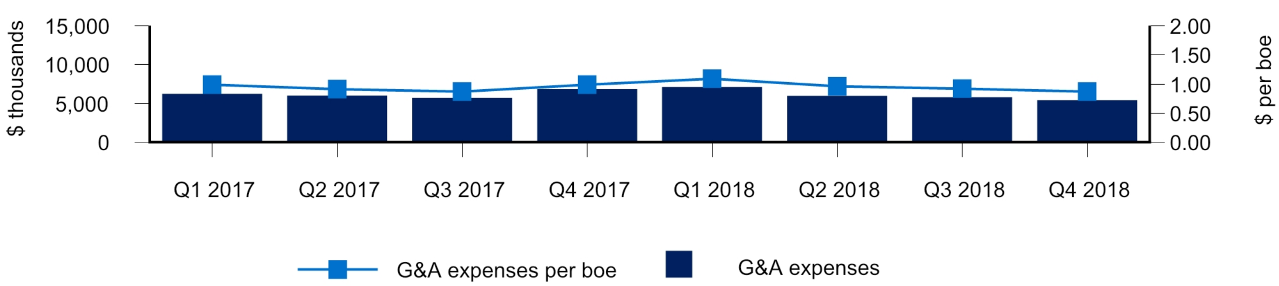
Cash costs for the year ended December 31, 2018, increased five percent to $9.39 per boe, as compared to $8.92 per boe for the year ended December 31, 2017. Similarly, cash costs for the three months ended December 31, 2018, increased three percent to $9.27 per boe, compared to $8.96 per boe for the same period of 2017. The increase in transportation expenses had the greatest impact to Bonavista's cash cost metric for the three months and year ended December 31, 2018, resulting from fixed priced transportation commitments to diversify Bonavista's sales points beyond AECO to the Dawn markets that commenced November 1, 2017.

### *General and administrative expenses*

The following sets forth Bonavista’s general and administrative expenses for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe amounts) | | | | | | |
| General and administrative expenses | **5,413** | 6,819 | (21)% | **24,291** | 24,749 | (2)% |
| Per boe | **0.87** | 0.99 | (12)% | **0.96** | 0.94 | 2 % |

**General and Administrative (G&A) Expenses**



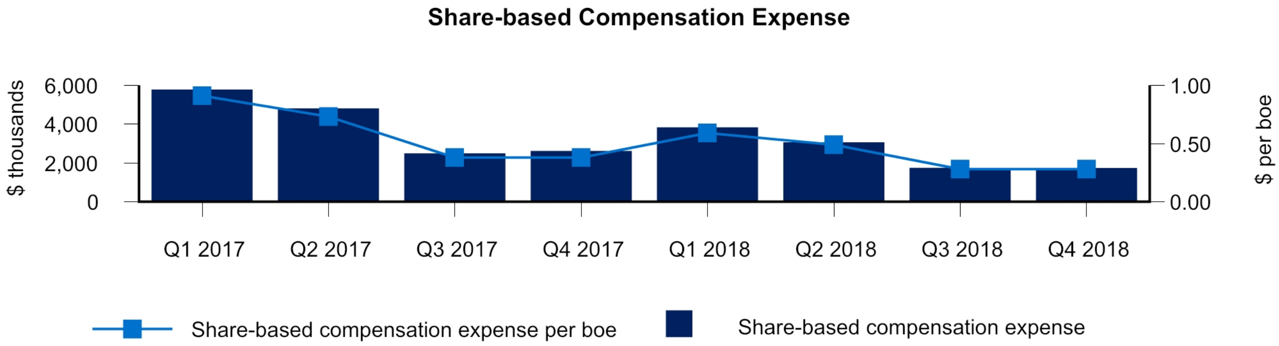

General and administrative expenses, after overhead recoveries, decreased two percent to $24.3 million for the year ended December 31, 2018 compared to $24.7 million for the same period of 2017. Despite a 38% decrease in capital overhead recoveries, initiatives taken to reduce Bonavista's administrative cost structure and discretionary spending more than offset the impact of a curtailed exploration and development program to support a decrease in general and administrative expenses on an absolute basis. These initiatives led to savings of approximately $2.7 million for the year ended December 31, 2018. On a per boe basis, general and administrative expenses increased two percent to $0.96 per boe for the year ended December 31, 2018 compared to $0.94 per boe for the same period of 2017, as a result of a four percent decrease in production volumes partially offset by the cost reductions noted above.

For the three months ended December 31, 2018, general and administrative expenses, after overhead recoveries, decreased 21% to $5.4 million compared to $6.8 million of the same period of 2017. Similarly, on a per boe basis, general and administrative expenses decreased 12% to $0.87 per boe for the three months ended December 31, 2018 compared to $0.99 per boe for the same period of 2017. The decrease in general and administrative expenses on an absolute and per boe basis resulted from a decrease in Bonavista's administrative costs structure and discretionary cost-saving initiatives which most notably saw a decrease in fees from third party service providers. These decreases more than offset the impact of a nine percent decrease in production volumes on a per boe basis.

### *Share-based compensation*

The following table sets forth Bonavista's share-based compensation expense recognized for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe amounts) | | | | | | |
| Share-based compensation expense | **1,732** | 2,614 | (34)% | **10,381** | 15,702 | (34)% |
| Per boe | **0.28** | 0.38 | (26)% | **0.41** | 0.60 | (32)% |




Share-based compensation expense recognized in connection with Bonavista's long-term incentive plans for the year ended December 31, 2018 was $10.4 million compared to $15.7 million recognized for the same period of 2017. For the year ended December 31, 2018, $0.7 million of share-based compensation expense was capitalized to property, plant and equipment compared to $1.4 million in the same period of 2017. Similarly, share-based compensation was $1.7 million for the three months ended December 31, 2018 compared to $2.6 million for the comparative 2017 period. For the three months ended December 31, 2018, $0.1 million of share-based compensation was capitalized in property, plant and equipment compared to $0.2 million in the same period of 2017.

The lower share-based compensation expense recognized for the three months and year ended December 31, 2018 was primarily due to the valuation of awards. The average grant price of awards issued in 2018 was $1.96 per award compared to an average price of $4.82 per award in 2017. This decrease was consistent with the decline in Bonavista's TSX share price when most awards are issued, specifically Bonavista's average share price for December 2016 was $4.88 per share compared to an average of $1.95 per share for December 2017. In addition, in January 2017 there was an issuance of 0.3 million restricted incentive awards which vested upon issue resulting in an additional $1.6 million of share-based compensation expense recognized for the year ended December 31, 2017.

### *Depletion, depreciation, amortization and impairment*

The following table sets forth Bonavista's depletion, depreciation, amortization and impairment expense recognized for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe amounts) | | | | | | |
| Depletion, depreciation and amortization expense | **56,177** | 65,514 | (14) % | **227,447** | 254,555 | (11 )% |
| Impairment expense | **—** | 215,000 | (100 )% | **—** | 215,000 | (100 )% |
| Depletion, depreciation, amortization and impairment expense | **56,177** | 280,514 | (80) % | **227,447** | 469,555 | (52) % |
| Per boe | **8.98** | 40.76 | (78) % | **9.01** | 17.83 | (49) % |

For the year ended December 31, 2018, depletion, depreciation, amortization and impairment expense decreased 52% to $227.4 million from $469.6 million for the same period of 2017. Similarly, on a per boe basis, depletion, depreciation, amortization and impairment expense decreased 49% to $9.01 per boe for the year ended December 31, 2018 compared to $17.83 per boe for the same period of 2017. The expense recognized for the year ended December 31, 2017, was impacted by a $215.0 million impairment charge. Bonavista identified indicators of impairment in two of its CGUs as at December 31, 2017, as a result of the combination of a sustained decline in forward commodity benchmark prices for natural gas, a reduction in future development plans and technical reserve revisions. As such an impairment charge of $28.0 million was recorded in relation to the British Columbia CGU and an impairment charge of $187.0 million was recorded in relation to the Central Alberta CGU.

Indicators of impairment were also determined to exist as at December 31, 2018, as a result of a sustained decline in forward commodity benchmark prices for natural gas. As such impairment tests were carried out on each of Bonavista's CGUs, the British Columbia, the West Central and the Deep Basin CGUs. In each impairment test the recoverable amount of the CGU was determined to exceed the carrying value and as such no impairment charge was recorded for the year ended December 31, 2018. The decrease in depletion, depreciation, amortization and impairment expense on an absolute and per boe basis for the year end December 31, 2018, was also impacted by a four percent decrease in production volumes on which depletion expense is based.

For the three months ended December 31, 2018, depletion, depreciation, amortization and impairment expense decreased 80% to $56.2 million from $280.5 million for the same period of 2017. Similarly, on a per boe basis, depletion, depreciation, amortization and impairment expense for the three months ended December 31, 2018 decreased 78% to $8.98 per boe compared to $40.76 per boe for the same period of 2017. The decrease in depletion, depreciation, amortization and impairment expense, on an absolute and per boe basis for the three months ended December 31, 2018, was largely the result of the impairment charge of $215.0 million recorded in the fourth quarter of 2017 in addition to a nine percent decrease in production volumes on which depletion expense is based.

The results of Bonavista's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in impairment charges or in the recovery of previously recorded impairment charges.

### *Net financing costs*

The following table sets forth net financing costs for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands, except for per boe amounts) | | | | | | |
| Interest expense [1] | **8,553** | 8,953 | (4) % | **35,141** | 38,118 | (8) % |
| Per boe | **1.37** | 1.30 | 5 % | **1.39** | 1.45 | (4) % |
| Net finance costs | **22,958** | 16,727 | 37 % | **66,450** | 21,209 | 213 % |
| Per boe | **3.67** | 2.43 | 51 % | **2.63** | 0.81 | 225 % |

Note:

(1) Interest on bank credit facility and senior unsecured notes.

For the year ended December 31, 2018, net finance costs increased to $66.5 million compared to net finance costs of $21.2 million for the same period of 2017. Similarly, for the year ended December 31, 2018, net finance costs on a per boe basis were higher at $2.63 per boe compared to net finance costs of $0.81 per boe for the year ended December 31, 2017. The increase in net finance costs, on an absolute and per boe basis, can be largely attributed to fluctuations in the CDN dollar to the US dollar exchange rate, impacting foreign exchange gains and losses associated with the revaluation of Bonavista's US denominated senior unsecured notes and unrealized gains and losses on Bonavista's financial instrument contracts.

For the three months ended December 31, 2018, net finance costs increased to $23.0 million compared to net finance costs of $16.7 million for the same period of 2017. Similarly, for the three months ended December 31, 2018, net finance costs on a per boe basis were higher at $3.67 per boe compared to net finance costs of $2.43 per boe for the three months ended December 31, 2017. The increase in net finance costs, on an absolute and per boe basis, can be largely attributed to similar reasons as stated above.

In contrast to the increase in net finance costs (inclusive of non-cash amounts), Bonavista's interest expense on long-term debt decreased eight percent to $35.1 million for the year ended December 31, 2018 compared to $38.1 million for the same period of 2017. Similarly, on a per boe basis, interest expense, decreased to $1.39 per boe for the year ended December 31, 2018 compared to $1.45 per boe for the same period of 2017. The decrease in interest expense, on an absolute and per boe basis was a result of lower overall debt levels due to the repayment of US denominated senior unsecured notes in June (US$25.0 million) and November (US$90.0 million) of 2017, in addition to a $1.8 million realized foreign exchange gain recognized on maturity of financial instrument contracts that coincided with interest payments on US dollar denominated senior unsecured notes. The decrease in borrowing costs was somewhat offset by an increase in interest expense in conjunction with higher average borrowings on the bank credit facility throughout the year.

For the three months ended December 31, 2018, interest expense decreased four percent to $8.6 million compared to interest expense of $9.0 million for the same period of 2017, for similar reasons as noted above. For the three months ended December 31, 2018, on a per boe basis interest expense was higher at $1.37 per boe compared to interest expense of $1.30 per boe for the three months ended December 31, 2017. The increase in interest expense, on a per boe basis, was primarily due to the impact of a nine percent decrease in production volumes.

### *Decommissioning liability*

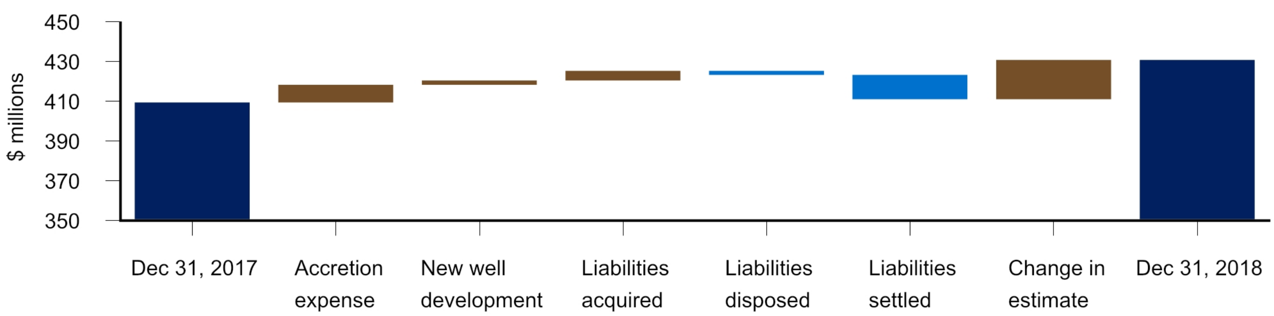
Bonavista's decommissioning liability results from net ownership interest in oil and natural gas assets including well sites, gathering systems and processing facilities. Bonavista has estimated the net present value of its total decommissioning liability to be $430.7 million at December 31, 2018, compared to an estimated net present value of $409.3 million at December 31, 2017. The estimated decommissioning liability includes management's estimates of abandonment and remediation costs and the time-frame in which the costs are expected to be incurred. An inflation rate and risk-free rate (based on the Bank of Canada's long-term risk-free bond rate) are used to calculate the present value of the decommissioning liability.

During the year ended 2018, Bonavista recognized decommissioning liabilities of $2.2 million in connection with its new well development activities and $4.8 million in relation to the acquisition of certain producing properties and a $19.8 million increase due to changes of estimated decommissioning liability. The change in estimate largely related to a decrease in the Bank of Canada's long-term risk-free rate to 2.2% as at December 31, 2018 compared to a rate of 2.3% used at December 31, 2017. Reflecting the increase in Bonavista's decommissioning liability with the passage of time, accretion expense of $8.9 million was recorded for the year ended December 31, 2018 in net finance costs on the statement of income (loss) and comprehensive income (loss). During the year ended 2018, Bonavista's decommissioning liability was reduced by $2.0 million as a result of the disposition of non-core properties and an additional reduction of $12.3 million as a result of Bonavista's active abandonment and reclamation program.

The timing of when decommissioning expenditures are incurred as part of Bonavista abandonment and reclamation program is predominately at the discretion of Bonavista's management. However, there is a non-discretionary component that relates to compliance with regulatory requirements and abandonment and reclamation projects where Bonavista is not the operator. For the year ended December 31, 2018 the non-discretionary component of Bonavista's $12.3 million abandonment and reclamation program was $3.6 million.

Bonavista is committed to operate in a safe, efficient and environmentally responsible manner and is committed to continually improving environmental, health and safety performance. As part of this commitment, Bonavista has an active abandonment and reclamation program that is regularly reviewed by Bonavista's Board of Directors and funded with adjusted funds flow and the bank credit facility. Bonavista's current Liability Management Rating ("LMR") is well within the Alberta Energy Regulator guidelines.

**Change in Decommissioning Liability**
**December 31, 2017 to December 31, 2018**




### *Deferred income tax expense (recovery)*

The deferred income tax provision for the year ended December 31, 2018 was $15.1 million compared to a deferred income tax recovery of $16.3 million recognized in the same period of 2017. The deferred income tax provision for the three months ended December 31, 2018 was $35.3 million compared to a deferred income tax recovery of $55.7 million recognized in the same period of 2017.

The deferred income tax provision for the three months and year ended December 31, 2018, was higher than the provision calculated using the statutory rate due to the income tax treatment of net foreign currency translation gains and losses on Bonavista's US denominated senior unsecured notes and financial instrument contracts and the income tax treatment of non-deductible share-based compensation expense. Bonavista made no cash payments or tax installments during the three months or year ended December 31, 2018 or for the comparative period of 2017.

At December 31, 2018, Bonavista's estimated income tax pools were $2.3 billion. It is expected that future taxable income will be available to utilize the accumulated tax pools. The following table sets forth Bonavista's estimated income tax pools by component for the year ended December 31, 2018 and December 31, 2017.

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Canadian oil and gas property expense | **435,744** | 482,916 |
| Canadian development expense | **447,826** | 544,348 |
| Canadian exploration expense | **369,612** | 340,252 |
| Undepreciated capital cost | **218,970** | 242,015 |
| Non-capital losses | **818,029** | 748,026 |
| Other | **6,954** | 5,523 |
| Total | **2,297,135** | 2,363,080 |

## CAPITAL EXPENDITURES

The following table sets forth Bonavista's capital expenditures by category for the three months and year ended December 31:

| | Three months ended December 31, | | | Year ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| ($ thousands) | | | | | | |
| Land acquisitions | **6,053** | 1,059 | 472 % | **8,746** | 11,620 | (25)% |
| Geological and geophysical | **1,109** | 1,461 | (24)% | **6,899** | 7,983 | (14)% |
| Drilling and completion | **30,172** | 45,400 | (34)% | **114,515** | 213,208 | (46)% |
| Production equipment and facilities | **7,838** | 11,802 | (34)% | **34,332** | 56,218 | (39)% |
| Exploration and development expenditures | **45,172** | 59,722 | (24)% | **164,492** | 289,029 | (43)% |
| Property acquisitions | **29,211** | 2,961 | 887 % | **32,654** | 13,736 | 138 % |
| Property dispositions | **(18,174)** | (5,035) | 261 % | **(26,616)** | (21,577) | 23 % |
| Office equipment | **221** | 9 | 2,356 % | **760** | 557 | 36 % |
| Net capital expenditures(1) | **56,430** | 57,657 | (2)% | **171,290** | 281,745 | (39)% |

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP Measures".

Capital expenditures for the three months and year ended December 31, 2018 were predominately focused on the natural gas liquids rich development in the West Central and Deep Basin core areas. For the year ended December 31, 2018, Bonavista's investment in exploration and development activities was $164.5 million, a 43% decrease compared to $289.0 million for the same period of 2017. Similarly, for the three months ended December 31, 2018, Bonavista's investment in exploration and development activities was $45.2 million, a 24% decrease compared to $59.7 million for the same period of 2017. The decrease in exploration and development expenditures, was the result of a reduced capital program driven by continued weakness in natural gas prices at AECO. Bonavista remains focused on maintaining a prudent capital spending program that is within adjusted funds flow to support the Corporation's objective of strengthening its financial flexibility.

During the year ended December 31, 2018, the total consideration received for non-core property dispositions was $26.6 million, resulting in a loss on the sale of property, plant and equipment of $6.7 million and a $0.2 million gain on the sale of exploration and evaluation assets. During the comparative period of 2017, Bonavista disposed of certain non-core properties for total consideration of $21.6 million, resulting in a gain on the sale of property, plant and equipment of $13.6 million and a $1.0 million gain on the sale of exploration and evaluation assets. During the year ended December 31, 2018, Bonavista acquired producing properties and petroleum and natural gas rights within its core areas for total consideration of $32.7 million compared to $13.7 million invested in the comparative period of 2017. Office equipment expenditures remained relatively consistent for the year ended December 31, 2018 and 2017, at $0.8 million and $0.6 million respectively.

During the three months ended December 31, 2018, the total consideration received for non-core property dispositions was $18.2 million, resulting in a loss on the sale of property, plant and equipment of $12.1 million. During the three months ended December 31, 2018, Bonavista acquired producing properties and petroleum and natural gas rights within its core areas for total consideration of $29.2 million compared to $3.0 million invested in the comparative period of 2017. Office equipment expenditures were relatively minor during the three months ended December 31, 2018 and 2017 at $0.2 million and $9,000 respectively.

## CAPITAL RESOURCES AND LIQUIDITY

Bonavista has a $500 million, covenant-based bank credit facility provided by a syndicate of eight domestic banks. At December 31, 2018, Bonavista had $13.0 million drawn on its bank credit facility and outstanding letters of credit of $17.3 million, which reduce the available borrowing capacity. At December 31, 2018, Bonavista had $469.7 million of unutilized capacity on its bank credit facility. At December 31, 2017, Bonavista had $72.9 million drawn on its bank credit facility and outstanding letters of credit of $18.0 million, providing a total unutilized capacity of $409.1 million.

The bank credit facility provides that advances be made by way of Canadian prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The total stamping fees range between 50 basis points and 215 basis points on Canadian bank prime and US base rate borrowings and between 150 basis points and 315 basis points on Canadian dollar bankers' acceptance and US dollar LIBOR borrowings. The undrawn portion of the bank credit facility is subject to a standby fee in the range of 30 to 63 basis points. For the year ended December 31, 2018 and December 31, 2017, borrowing costs averaged 4.0% and 3.6%, respectively.

Bonavista's senior unsecured notes totaled $790.7 million at December 31, 2018 consisting of US$565.0 million (CDN$770.7 million) and CDN$20.0 million. At December 31, 2017, Bonavista's senior unsecured notes totaled $730.4 million at December 31, 2017 consisting of US$565.0 million (CDN$710.4 million) and CDN$20.0 million. Bonavista's senior unsecured notes bear fixed interest rates, with a weighted average interest rate of 4.1% and a three-and-a-half-year weighted average life with maturity dates ranging from November 2, 2020 to May 23, 2025.

Although, the underlying value of Bonavista's senior unsecured notes did not change between December 31, 2018 and December 31, 2017, its overall indebtedness increased as a result of the revaluation of its US denominated senior unsecured notes at the end of the reporting period. This revaluation resulted in an unrealized foreign exchange loss of $60.3 million for the year ended December 31, 2018. The unrealized loss was due to the weakening of the CDN dollar relative to the US dollar, which at December 31, 2018 was $1.3641 CDN$/US$ compared to the December 31, 2017 rate of $1.2573 CDN$/US$. Bonavista has entered into financial instrument contracts to reduce its exposure to the CDN dollar to the US dollar exchange rate associated with the future cash repayments of its US denominated senior unsecured notes. The underlying notional amount of the financial instrument contracts maturing on the maturity dates of Bonavista US denominated senior unsecured notes is US$400 million at an average rate of CDN$/US$ of $1.3015.

At December 31, 2018, Bonavista's net debt was $835.9 million with net debt to fourth quarter of 2018 annualized adjusted funds flow ratio of 3.4:1. In comparison to December 31, 2017, Bonavista's net debt was $840.2 million with net debt to fourth quarter of 2017 annualized adjusted funds flow ratio of 2.4:1. This ratio represents the time period it would take to pay off Bonavista's net debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio may increase at certain times as a result of acquisitions, low commodity prices and foreign exchange fluctuations.

The following table provides a reconciliation of long-term debt to net debt and the net debt to adjusted funds flow ratio:

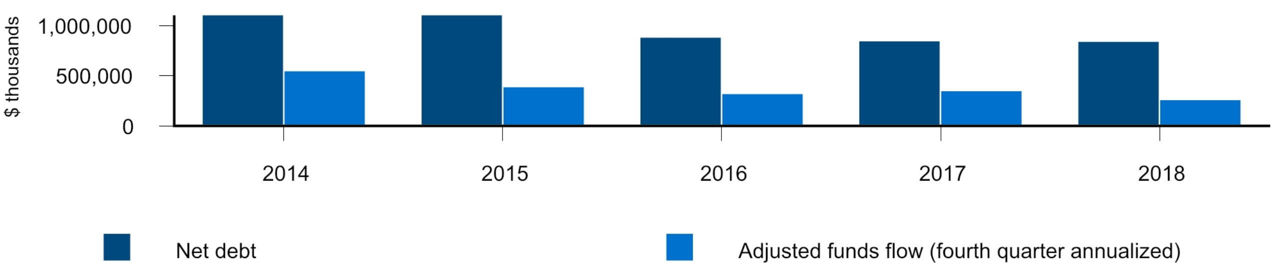
| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Long-term debt | **801,625** | 800,544 |
| Working capital(2) | **(8,545)** | 29,425 |
| Current assets | | |
| Financial instrument commodity contracts | **57,192** | 64,496 |
| Current liabilities | | |
| Financial instrument commodity contracts | **(2,663)** | (38,146) |
| Decommissioning liabilities | **(11,704)** | (16,146) |
| Net debt(1) | **835,905** | 840,173 |
| Adjusted funds flow (fourth quarter annualized)(1) | **244,300** | 344,432 |
| Net debt to adjusted funds flow (fourth quarter annualized) (ratio) | **3.4:1** | 2.4:1 |
| Adjusted funds flow(2) | **259,595** | 301,988 |
| Net debt to adjusted funds flow (ratio) | **3.2:1** | 2.8:1 |

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

(2) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million. Current assets as at December 31, 2017 were $152.6 million compared to current liabilities of $182.1 million.

## Net Debt to Adjusted Funds Flow




Bonavista's Board of Directors has approved a net capital expenditure budget of between $130 and $170 million to accommodate the drilling of 24 to 32 gross wells generating annual average production from 65,000 to 69,000 boe per day. This program will focus on liquids rich opportunities, but also allows for flexibility in capital allocation as supported by changing commodity prices.

Bonavista has budgeted for between $9 and $11 million of decommissioning expenditures for 2019 of which $2.3 million pertains to abandonment and reclamation projects where Bonavista is not the operator and $1.2 million for regulatory compliance projects. In addition, Bonavista expects to maintain its quarterly dividend policy of $0.01 per share. Together, this will generate adjusted funds flow of between $170 and $200 million and a payout ratio(1) from 85% to 95%. Bonavista expects to fund its capital expenditure program, dividend program and abandonment and decommissioning expenditures within adjusted funds flow(1). Bonavista also has unused capacity on its bank credit facility that will be utilized if necessary, however it remains Bonavista's objective to fund its current abandonment and reclamation program, dividend payments and net capital expenditures(1) necessary for the replacement of production declines using only adjusted funds flow(1).

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

### *Debt covenants*

Under the terms of the bank credit facility and senior unsecured notes, Bonavista has provided the covenants that its:

- consolidated senior debt borrowing will not exceed three and one half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment;
- consolidated total debt will not exceed three and one half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and
- consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholders' equity of the Corporation, in all cases calculated based on a rolling prior four quarters.

Bonavista's consolidated senior debt and consolidated total debt were the same at December 31, 2018 and include Bonavista's senior unsecured notes issued under the master shelf agreement, senior unsecured notes not subject to the master shelf agreement and the bank credit facility. Bonavista's consolidated senior debt may differ from total debt in instances when the Corporation issues senior subordinated debt or enters into a significant capital lease obligation or guarantee.

At December 31, 2018, Bonavista was in compliance with all covenants under its credit facilities and senior unsecured notes. Total long-term debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and total senior debt to EBITDA was 2.8 times compared to the covenant of less than 3.5 times and total long-term debt to capitalization was 0.35 times compared to the covenant of less than 0.5 times. The ratio of total senior debt to EBITDA, total debt to EBITDA and total long-term debt to capitalization are susceptible to factors that impact earnings, the most significant of which are changes in commodity prices.

## OUTSTANDING SHARE INFORMATION

### *Shareholders' equity*

At December 31, 2018, Bonavista had 260.1 million equivalent common shares outstanding. This includes 3.1 million exchangeable shares, which are exchangeable into 4.6 million common shares. The exchange ratio in effect at December 31, 2018 for exchangeable shares was 1.48526:1.

At December 31, 2018, Bonavista had 3.0 million restricted incentive awards and 4.1 million performance incentive awards outstanding under Bonavista's long-term incentive plans.

The following provides a reconciliation of Bonavista's common share and exchangeable share balance for the year ended December 31, 2018:

| | Common Shares | Exchangeable Shares |
|---|---|---|
| | (thousands) | (thousands) |
| Balance as at December 31, 2016 | 249,277 | 3,259 |
| Issued on conversion of exchangeable shares | 30 | — |
| Exchanged for common shares | — | (21) |
| Conversion of restricted incentive and performance incentive awards | 2,440 | — |
| Balance as at December 31, 2017 | 251,747 | 3,238 |
| Issued on conversion of exchangeable shares | **196** | **—** |
| Exchanged for common shares | **—** | **(133)** |
| Conversion of restricted incentive and performance incentive awards | **3,510** | **—** |
| Balance as at December 31, 2018 | **255,453** | **3,105** |

At February 14, 2019, Bonavista had 260.3 million equivalent common shares outstanding. This includes 3.1 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect on February 14, 2019 for exchangeable shares was 1.49889:1. In addition as of February 14, 2019, Bonavista had 5.8 million restricted incentive awards and 5.1 million performance incentive awards outstanding under its long-term incentive plans.

### *Dividends*

For the three months ended December 31, 2018, Bonavista paid cash dividends of $2.6 million ($0.01 per share) compared to $2.5 million ($0.01 per share) for the same period of 2017. For the year ended December 31, 2018, Bonavista paid cash dividends of $10.1 million ($0.04 per share) compared to $10.0 million ($0.04 per share) for the same period of 2017.

Bonavista announces its dividend policy on a quarterly basis and confirms its dividend payment on a quarterly basis. Dividends are approved by the Board of Directors and are dependent upon the commodity price environment, production levels and the amount of capital expenditures to be financed from adjusted funds flow.

On December 14, 2018, Bonavista's Board of Directors declared a quarterly dividend of $0.01 per share, payable in cash to shareholders of record on December 31, 2018. The dividend payment date was January 16, 2019.

### *Contractual obligations and commitments*

Bonavista enters into various contractual obligations and commitments in the normal course of operations. The following table provides a summary of Bonavista's contractual obligations and commitments at December 31, 2018:

| | Total | 2019 | 2020 | 2021 | 2022 | 2023 and thereafter |
|---|---|---|---|---|---|---|
| ($ thousands) | | | | | | |
| Long-term debt repayments(1)(3)(4) | 801,625 | — | 218,033 | 216,268 | 68,084 | 299,240 |
| Interest payments(2)(3) | 115,159 | 32,582 | 31,019 | 21,475 | 13,683 | 16,400 |
| Office lease(5) | 10,703 | 6,760 | 3,943 | — | — | — |
| Transportation expenses(6) | 147,106 | 31,682 | 29,732 | 27,651 | 25,830 | 32,211 |
| Total contractual obligations | **1,074,593** | **71,024** | **282,727** | **265,394** | **107,597** | **347,851** |

Notes:

(1) Long-term debt repayments include the principal payments due on senior unsecured notes. Based on the existing terms of the revolving bank credit facility, the amounts owing under this facility are required to be paid on September 10, 2021.
(2) Fixed interest payments on senior unsecured notes.
(3) US dollar payments are converted using the exchange rate at December 31, 2018 of $1.3641 CDN to $1.0000 US dollar.
(4) With respect to the long-term debt repayment obligations Bonavista has entered into financial instrument contracts to reduce its exposure to the CDN dollar to the US dollar exchange rate associated with the future cash repayments of its US denominated senior unsecured notes. The underlying notional amount of the financial instrument contracts maturing on the maturity dates of Bonavista US denominated senior unsecured notes is US$400 million at an average CDN$/US$ rate of $1.3015.
(5) Office lease expires July 31, 2020.
(6) Includes a Long Term Fixed Price (LTFP) contract with TransCanada that commenced November 1, 2017. This 10-year contract contains an early termination policy after 5 years which has been assumed to be exercised in the contractual obligation above.

Contractual obligations and commitments that are not material have been excluded from the above table.

## OFF-BALANCE SHEET TRANSACTIONS

Bonavista has certain lease arrangements, which are reflected in the contractual obligations and commitments table above, which are entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on Bonavista's consolidated statement of financial position as at December 31, 2018.

## SUMMARY OF HISTORICAL QUARTERLY RESULTS

The following table provides a summary of Bonavista's quarterly results for the eight most recently completed quarters:

| | 2018 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| **Quarter ending** | **Dec 31, 2018** | Sep 30, 2018 | Jun 30, 2018 | Mar 31, 2018 | Dec 31, 2017 | Sep 30, 2017 | Jun 30, 2017 | Mar 31, 2017 |
| **Financial** | | | | | | | | |
| ($ thousands, except per boe and per share amounts) | | | | | | | | |
| Production revenues | **124,302** | 131,175 | 121,102 | 138,388 | 147,188 | 121,901 | 140,731 | 143,182 |
| Net income (loss) | **81,227** | (17,811) | (49,564) | (2,037) | (159,149) | (1,699) | 44,490 | 88,428 |
| Per share(1) | **0.31** | (0.07) | (0.19) | (0.01) | (0.62) | (0.01) | 0.17 | 0.35 |
| Cash flow from operating activities | **77,581** | 73,720 | 63,842 | 76,048 | 94,515 | 75,268 | 79,143 | 76,693 |
| Per share(1) | **0.30** | 0.28 | 0.25 | 0.30 | 0.37 | 0.29 | 0.31 | 0.30 |
| Adjusted funds flow(2) | **61,075** | 63,688 | 65,704 | 69,128 | 86,108 | 68,459 | 76,570 | 70,851 |
| Per share(1) | **0.23** | 0.25 | 0.25 | 0.27 | 0.33 | 0.27 | 0.30 | 0.28 |
| Dividends declared | **2,555** | 2,554 | 2,536 | 2,523 | 2,518 | 2,516 | 2,503 | 2,503 |
| Per share(1) | **0.01** | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Total assets | **2,923,709** | 2,845,288 | 2,889,457 | 2,933,854 | 2,959,470 | 3,194,720 | 3,210,082 | 3,242,319 |
| Shareholders' equity | **1,552,184** | 1,471,682 | 1,490,460 | 1,539,073 | 1,539,461 | 1,698,486 | 1,699,898 | 1,652,722 |
| Long-term debt(3) | **801,625** | 760,231 | 809,099 | 802,394 | 800,544 | 833,909 | 866,888 | 921,731 |
| Net debt(2) | **835,905** | 795,023 | 826,552 | 839,619 | 840,173 | 853,616 | 861,784 | 891,737 |
| Capital expenditures: | | | | | | | | |
| Exploration and development | **45,172** | 42,317 | 33,148 | 43,855 | 59,722 | 77,213 | 59,820 | 92,274 |
| Acquisitions, net of dispositions(4) | **11,037** | (5,821) | 725 | 97 | (2,074) | 2,063 | (290) | (7,540) |
| Corporate | **221** | 57 | 337 | 145 | 9 | 98 | 314 | 136 |
| Weighted average outstanding equivalent shares: (thousands)(1) | | | | | | | | |
| Basic | **260,047** | 259,897 | 258,002 | 257,030 | 256,386 | 256,177 | 254,965 | 254,586 |
| Diluted | **267,135** | 266,913 | 266,999 | 267,120 | 262,980 | 262,805 | 262,958 | 262,519 |
| **Operating** | | | | | | | | |
| (boe conversion – 6:1 basis) | | | | | | | | |
| Production: | | | | | | | | |
| Natural gas (mmcf/day) | **281** | 287 | 301 | 322 | 318 | 301 | 310 | 293 |
| Natural gas liquids (bbls/day) | **19,131** | 17,868 | 15,950 | 16,480 | 19,284 | 18,639 | 18,364 | 18,888 |
| Oil (bbls/day)(5) | **2,108** | 2,358 | 2,091 | 2,327 | 2,463 | 2,350 | 2,288 | 2,560 |
| Total oil equivalent (boe/day) | **68,011** | 68,036 | 68,214 | 72,417 | 74,799 | 71,191 | 72,313 | 70,281 |
| Product prices:(6) | | | | | | | | |
| Natural gas ($/mcf) | **2.91** | 2.76 | 2.62 | 2.85 | 3.14 | 2.84 | 3.10 | 3.12 |
| Natural gas liquids ($/bbl) | **24.99** | 28.90 | 32.56 | 31.68 | 28.47 | 26.22 | 27.91 | 26.52 |
| Oil ($/bbl)(5) | **28.47** | 58.84 | 64.15 | 59.81 | 59.49 | 54.20 | 58.91 | 58.50 |
| Total oil equivalent ($/boe) | **19.91** | 21.27 | 21.16 | 21.79 | 22.65 | 20.68 | 22.24 | 22.27 |
| Operating expenses ($/boe) | **5.66** | 5.74 | 5.78 | 5.64 | 5.57 | 5.69 | 5.61 | 5.47 |
| Transportation expense ($/boe) | **1.37** | 1.42 | 1.32 | 1.23 | 1.10 | 0.84 | 0.86 | 0.96 |
| General and administrative expenses ($/boe) | **0.87** | 0.92 | 0.96 | 1.09 | 0.99 | 0.87 | 0.91 | 0.99 |
| Cash costs ($/boe)(2) | **9.27** | 9.46 | 9.47 | 9.38 | 8.96 | 8.75 | 8.96 | 8.98 |
| Operating netback ($/boe)(2) | **11.99** | 12.48 | 12.95 | 13.11 | 14.81 | 12.68 | 14.14 | 13.75 |
| **Trading Statistics** | | | | | | | | |
| ($ per share, except volume) | | | | | | | | |
| High | **1.60** | 1.63 | 1.75 | 2.32 | 3.01 | 3.37 | 3.56 | 5.22 |
| Low | **1.01** | 1.25 | 1.13 | 1.11 | 1.77 | 2.55 | 2.22 | 3.05 |
| Close | **1.20** | 1.49 | 1.49 | 1.18 | 2.25 | 2.98 | 2.71 | 3.46 |
| Average Daily Volume - Shares | **817,647** | 527,770 | 1,086,460 | 1,070,659 | 860,422 | 617,169 | 822,516 | 819,104 |

Notes:

(1) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(2) Reference should be made to the section entitled "Non-GAAP Measures".
(3) Includes the current portion of long-term debt.
(4) Expenditures on property acquisitions, net of property dispositions.
(5) Oil includes light, medium and heavy oil.
(6) Product prices include realized gains and losses on financial instrument commodity contracts.

Production revenues over the past eight quarters have fluctuated largely due to the volatility of commodity prices and changes in production volumes. Net income (loss) in the past eight quarters has fluctuated from a net loss of $159.1 million in the fourth quarter of 2017 to net income of $88.4 million in the first quarter of 2017. These fluctuations are primarily influenced by commodity prices, realized and unrealized gains and losses on financial instrument contracts, unrealized gains and losses on the revaluation of Bonavista's US dollar denominated senior unsecured notes, gains and losses on the acquisition and disposition of property, plant and equipment, gains and losses on the disposition of exploration and evaluation assets and impairment charges.

## CONTROLS AND PROCEDURES

### *Disclosure controls and procedures*

The Corporation's Chief Executive Officer and Chief Financial Officer (the "Certifying Officers") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 - *Certification of Disclosure in Issuer's Annual and Interim Filings* ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Certifying Officers by others, particularly during the period in which the annual and interim filings or other reports filed or submitted by the Corporation under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's DC&P at December 31, 2018 and have concluded that the Corporation's DC&P were effective at December 31, 2018.

### *Internal control over financial reporting*

The Corporation’s Certifying Officers have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by National Instrument 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the generally accepted accounting principles applicable to the Corporation. The control framework the Certifying Officer used to design the Corporation's ICFR is "Internal Control - Integrated Framework (2013)" published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's ICFR at December 31, 2018 and have concluded that the Corporation's ICFR was effective at December 31, 2018. There were no changes in the Corporation's ICFR that occurred during the period beginning on October 1, 2018 and ended on December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

While the Certifying Officers believe that the Corporation's ICFR provides a reasonable level of assurance and is effective, they do not expect that the ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

## CRITICAL ACCOUNTING ESTIMATES

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). A summary of the significant accounting policies are presented in note 4, "Significant Accounting Policies" of the Notes to the Financial Statements. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Bonavista's operating environment changes.

Estimates and underlying assumptions are reviewed on an ongoing basis by management. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The key sources of estimation uncertainty to the carrying amounts of assets and liabilities are discussed below:

i. Determination of a Cash-Generating Unit (“CGU”)

   The determination of Bonavista’s CGUs is subject to management’s judgment. In determining Bonavista’s CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. On December 31, 2018, the Corporation re-aligned certain cash-generating units to be consistent with the operations of Bonavista's current asset base by combining the Central Alberta CGU and South Central Alberta CGU to form the West Central CGU. Bonavista's current CGU composition includes its British Columbia CGU, Deep Basin CGU and West Central CGU.

ii. Impairment testing

   Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less costs of disposal and value in use and is subject to management estimates. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

At December 31, 2018, Bonavista evaluated each of its CGUs for indicators of potential impairment or a reversal of previously recorded impairment charges. Key estimates used in the determination of cash flows used to calculate the recoverable amount of a CGU include: quantities of reserves and future production; future commodity pricing; development costs; operating costs; royalty obligations; and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU. Bonavista identified indicators of impairment at December 31, 2018 as a result of a sustained decline in forward commodity benchmark prices for natural gas. As such impairment tests were conducted on each of Bonavista's CGUs at December 31, 2018, refer to note 11, "Property, Plant and Equipment". Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

iii. Proved plus probable oil and natural gas reserves

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income, as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments or reversals.

iv. Depreciation, depletion, amortization and impairment

Property, plant and equipment is measured at cost less accumulated depreciation, depletion, amortization and impairment. Bonavista's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved and probable reserves.

v. Decommissioning liability

The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions.

vi. Financial instrument contracts

The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation's financial instrument contracts are subject to changes in foreign exchange rates.

## FUTURE ACCOUNTING POLICIES

Below is a description of a new IFRS standard that is not yet effective and has not been applied in the preparation of the financial statements. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material impact on Bonavista's financial statements.

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces IAS 17 *Leases*. The new standard introduces a single recognition and measurement model for leases, which requires the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. The new standard is to be adopted either retrospectively or using a modified retrospective approach. Bonavista intends to adopt IFRS 16 in its financial statements for the period beginning on January 1, 2019, using the modified retrospective transition approach. The Corporation is currently in the process of quantifying the impact of the contracts that fall within the scope of the new standard. The Corporation expects adjustments for its office lease, certain vehicles and certain field equipment, however, the full extent of the impact has not yet been finalized.

## RISK FACTORS AND RISK MANAGEMENT

The following are the primary risks associated with the business of Bonavista. Most of these risks are similar to those affecting others in the conventional oil and natural gas sector. Bonavista's financial position and results of operations are directly impacted by these factors:

- Operational risks associated with the exploration, development and production of oil and natural gas;
- Commodity risk as crude oil, condensate and natural gas prices and differentials fluctuate due to market forces;
- Market risk relating to global supply and demand for oil and natural gas and market prices for oil and natural gas;
- Market risk relating to Bonavista's ability to acquire capacity on pipelines to deliver natural gas to commercial markets;
- Political uncertainty in Canada and the impact on liquefied natural gas and other infrastructure projects;
- Operational risk associated with third party facility outages and downtime;
- Reserves risk with respect to the quantity and quality of recoverable reserves;
- Financial risk such as volatility of the CDN$/US$ dollar exchange rate, interest rates and debt service obligations;
- Financial risk relating to change in investor sentiment towards oil and natural gas operations;
- Risk associated with the re-negotiation of Bonavista's credit facility and the continued participation of Bonavista's lenders;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices, fracturing regulations and environmental protection relating to the oil and natural gas industry; and

- Labour risk related to availability, productivity and retention of qualified personnel.

Bonavista seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price volatility;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining a risk management program that allows for Bonavista to enter into a financial instrument commodity contract to reduce Bonavista's exposure of commodity price volatility;
- Adhering to Bonavista’s safety program and keeping abreast of current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs;
- Increasing transparency over social, environment and governance policies and practices through corporate responsibility reporting;
- Closely monitoring performance against financial covenants and preparing forecasts;
- Closely monitoring commodity prices and capital programs to manage financial leverage; and
- Monitoring the debt and equity markets to understand how changes in the capital markets may impact Bonavista's business plan.

While the foregoing list notes the primary business risks to Bonavista, it is not exhaustive. For additional information on Bonavista's business risks and how Bonavista seeks to mitigate them reference should be made to the "Risk Factors" section in Bonavista's Annual Information Form which is available through SEDAR at www.sedar.com or can be obtained from Bonavista’s website at www.bonavistaenergy.com.

## ABBREVIATIONS

| | |
|---|---|
| AECO | benchmark price for natural gas determined at the AECO 'C' hub in southeast Alberta |
| AER | Alberta Energy Regulator |
| bbl | barrel |
| bbls | barrels |
| bbls per day | barrels per day |
| boe | barrel(s) of oil equivalent |
| boe per day | barrels of oil equivalent per day |
| Chicago | Chicago city-gate benchmark price for natural gas |
| CNWY PN | Conway propane benchmark price |
| DAWN | natural gas traded at Union Gas Dawn hub in Dawn Township, Ontario |
| GAAP | generally accepted accounting principles |
| GJ | gigajoule |
| GLJ | GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta |
| IFRS | International Financial Reporting Standards |
| LNG | Liquefied natural gas |
| LTFP | Long term fixed price contract |
| NGLs | natural gas liquids |
| NGTL | NOVA Gas Transmission Ltd. |
| NYMEX | New York Mercantile Exchange natural gas futures benchmark price |
| mcf | thousand cubic feet |
| mcf per day | thousand cubic feet per day |
| Mcfe | Mcf of natural gas equivalent |
| mmcf | million cubic feet |
| mmcf per day | million cubic feet per day |
| MMbtu | million British Thermal Units |
| MSW | benchmark price for mixed sweet crude determined at Edmonton, Alberta |
| MTB BT | Mont Belvieu 65 nC4/35 iC4 benchmark price |
| tcf | trillion cubic feet |
| Ventura | natural gas traded at Ventura in Hancock County, Iowa |
| WCSB | Western Canadian Sedimentary Basin |
| WTI | West Texas Intermediate |
| TCPL | TransCanada Pipelines |

## NON-GAAP MEASURES

The Corporation uses terms that are commonly used in the oil and natural gas industry, but do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. Management believes that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

The following list identifies the non-GAAP measures included in Bonavista's MD&A, a description of how the measure has been calculated by Bonavista, a discussion of why Bonavista's management has deemed the measure to be useful and a reconciliation to the most comparable GAAP measure.

- **Adjusted funds flow**

  Adjusted funds flow is based on cash flow from operating activities, excluding changes in non-cash working capital, decommissioning expenditures and including interest expense. Where working capital is equal to current assets less current liabilities.

  Bonavista considers adjusted funds flow to be a key measure that provides a more complete understanding of Bonavista's ability to generate cash flow necessary to finance capital expenditures, expenditures on decommissioning obligations, fund its dividend program and meet its financial obligations. Bonavista considers its capital structure to include working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities), bank credit facility, senior unsecured notes and shareholders' equity. Bonavista monitors capital based on the ratio of net debt to adjusted funds flow (annualized current quarter).

  Certain non-cash charges and decommissioning expenditures have been excluded from the calculation of adjusted funds flow, as management believes the timing of collection, payment and incurrence is variable and by excluding them from the calculation management is able to provide a more meaningful measure of Bonavista's cash flow on a continuing basis. More specifically, expenditures on decommissioning liabilities may vary from period to period depending on Bonavista's capital programs and the maturity of its operating areas. The settlement of decommissioning obligations is managed through Bonavista's capital budgeting process which considers its available adjusted funds flow. Reference should be made to note 8, "Capital Management" of the financial statements.

  The following table provides a reconciliation between the non-GAAP measure of adjusted funds flow to the most directly comparable GAAP measure of cash flow from operating activities:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands) | | | | |
| Cash flow from operating activities | **77,581** | 94,515 | **291,191** | 325,619 |
| Interest expense[1] | **(8,553)** | (8,953) | **(35,141)** | (38,118) |
| Decommissioning expenditures[3] | **2,198** | 5,746 | **12,318** | 17,318 |
| Changes in non-cash working capital[2] | **(10,151)** | (5,200) | **(8,773)** | (2,831) |
| Adjusted funds flow | **61,075** | 86,108 | **259,595** | 301,988 |

Notes:

(1) Interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) Refer to note 10, "Supplemental cash flow information" in the financial statements.
(3) The timing of when decommissioning expenditures are incurred is predominately at the discretion of Bonavista's management. However, there is a non-discretionary component that relates to compliance with regulatory requirements and abandonment and reclamation projects where Bonavista is not the operator. For the three months ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $0.6 million (December 31, 2017 - $1.3 million). Similarly, for the year ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $3.6 million (December 31, 2017 - $3.1 million).

- **Operating netback**

  Operating netback is equal to production revenues and realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation expenses. Operating netback per boe is calculated by dividing operating netback by total production volumes sold in the period.

  Bonavista's management believes that operating netback is a key industry benchmark and a measure of operating performance that assists management and investors in assessing Bonavista's profitability. Operating netback on a per boe basis assists Bonavista's management and investors in evaluating operating performance on a comparable basis.

The following table provides a reconciliation between the non-GAAP measure of operating netback to the most directly comparable GAAP measure of net income (loss) for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands, except for per boe amounts) | | | | |
| Net income (loss) | **81,227** | (159,149) | **11,815** | (27,930) |
| Adjustments for: | | | | |
| Unrealized losses (gains) on financial instrument commodity contracts | **(139,841)** | 9,187 | **(43,014)** | (107,614) |
| General and administrative expenses | **5,413** | 6,819 | **24,291** | 24,749 |
| Share-based compensation expense | **1,732** | 2,614 | **10,381** | 15,702 |
| Loss (gain) on disposition of property, plant and equipment | **12,057** | (135) | **6,725** | (13,589) |
| Loss (gain) on disposition of exploration and evaluation assets | **9** | 963 | **(167)** | (976) |
| Depletion, depreciation, amortization and impairment | **56,177** | 280,514 | **227,447** | 469,555 |
| Net finance costs | **22,958** | 16,727 | **66,450** | 21,209 |
| Deferred income expense (recovery) | **35,309** | (55,660) | **15,099** | (16,251) |
| Operating netback | **75,041** | 101,880 | **319,027** | 364,855 |
| Operating netback per boe | **11.99** | 14.81 | **12.63** | 13.85 |

For additional reference the following table provides a compilation of the line items from Bonavista's consolidated statement of income (loss) that comprise operating netback on a per boe basis for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ per boe) | | | | |
| Production revenues | **19.87** | 21.39 | **20.40** | 21.00 |
| Realized gains on financial instrument commodity contracts | **0.04** | 1.26 | **0.64** | 0.97 |
| Production revenues and realized gains on financial instrument commodity contracts | **19.91** | 22.65 | **21.04** | 21.97 |
| Royalties | **0.89** | 1.17 | **1.36** | 1.58 |
| Operating expense | **5.66** | 5.57 | **5.70** | 5.59 |
| Transportation expense | **1.37** | 1.10 | **1.34** | 0.94 |
| Operating netback | **11.99** | 14.81 | **12.64** | 13.85 |

- **Operating margin**

Operating margin is equal to production revenues and realized gains and losses on financial instrument commodity contracts less royalties, operating expenses and transportation expenses; divided by production revenues and realized gains and losses on financial instrument commodity contracts. Realized gains and losses on financial instrument commodity contracts represent the portion of Bonavista's financial instrument commodity contracts that have settled in cash during the period and disclosing this impact provides transparency on how Bonavista's risk management program impacts the operating netback and operating margin metrics. Operating margin is calculated using per boe amounts.

Operating margin is used by management to show operating performance at both a disaggregated (core area) and aggregated level (corporate). This metric is used by management to illustrate the proportion of Bonavista's revenue available for expenditures after operating expenditures are considered.

The following table sets forth the details of the calculation of the operating margin ratio for the three months and year ending December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ per boe) | | | | |
| Production revenues | **19.87** | 21.39 | **20.40** | 21.00 |
| Realized gains on financial instrument commodity contracts | **0.04** | 1.26 | **0.64** | 0.97 |
| Production revenues and realized gains on financial instrument commodity contracts | **19.91** | 22.65 | **21.04** | 21.97 |
| Royalties | **0.89** | 1.17 | **1.36** | 1.58 |
| Operating expense | **5.66** | 5.57 | **5.70** | 5.59 |
| Transportation expense | **1.37** | 1.10 | **1.34** | 0.94 |
| Operating netback | **11.99** | 14.81 | **12.64** | 13.85 |
| Operating margin(1) | **60%** | 65% | **60%** | 63% |

Note:

(1) Ratio of operating netback to production revenues and realized gains on financial instrument commodity contracts.

- **Cash costs**

Cash costs are equal to the total of operating, transportation, general and administrative, and interest expenses. Cash costs per boe are calculated by dividing cash costs by total production volumes sold in the period.

Bonavista's management uses cash costs in assessing the Corporation's operating efficiency and controllable cost structure. Bonavista’s management believes that cash costs is a useful measure used by investors when evaluating Bonavista’s operating performance. Cash costs on a per boe basis also assists Bonavista’s management and investors in evaluating Bonavista's cash costs on a comparable basis with prior periods.

The following table provides a reconciliation between the non-GAAP measure of cash costs to the most directly comparable GAAP measure of net income (loss) for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands, except for per boe amounts) | | | | |
| Net income (loss) | **81,227** | (159,149) | **11,815** | (27,930) |
| Adjustments for: | | | | |
| Production revenues, net of royalties and financial instrument contracts | **(258,867)** | (138,620) | **(539,704)** | (644,505) |
| Share-based compensation expense | **1,732** | 2,614 | **10,381** | 15,702 |
| Loss (gain) on disposition of property, plant and equipment | **12,057** | (135) | **6,725** | (13,589) |
| Loss (gain) on disposition of exploration and evaluation assets | **9** | 963 | **(167)** | (976) |
| Depletion, depreciation, amortization and impairment | **56,177** | 280,514 | **227,447** | 469,555 |
| Net finance costs (income) excluding interest expense | **14,405** | 7,774 | **31,309** | (16,909) |
| Deferred income expense (recovery) | **35,309** | (55,660) | **15,099** | (16,251) |
| Cash costs | **(57,951)** | (61,699) | **(237,095)** | (234,903) |
| Cash costs per boe | **(9.27)** | (8.96) | **(9.39)** | (8.92) |

For additional reference the following table provides a compilation of the line items from Bonavista's consolidated statement of income (loss) that comprise cash costs on a per boe basis for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ per boe) | | | | |
| Operating expenses | **5.66** | 5.57 | **5.70** | 5.59 |
| Transportation expenses | **1.37** | 1.10 | **1.34** | 0.94 |
| General and administrative expenses | **0.87** | 0.99 | **0.96** | 0.94 |
| Interest expense | **1.37** | 1.30 | **1.39** | 1.45 |
| Cash costs | **9.27** | 8.96 | **9.39** | 8.92 |

- **Net capital expenditures**

Net capital expenditures is equal to cash flow used in investing activities, excluding changes in non-cash working capital.

Bonavista considers net capital expenditures to be a useful measure of cash flow used for capital reinvestment.

The following table provides a reconciliation between the non-GAAP measure of net capital expenditures to the most directly comparable GAAP measure of cash flow used in investing activities for the three months and year ended December 31:

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands) | | | | |
| Cash flow used in investing activities | **(59,972)** | (68,274) | **(188,094)** | (282,773) |
| Changes in non-cash working capital | **3,542** | 10,617 | **16,804** | 1,028 |
| Net capital expenditures | **(56,430)** | (57,657) | **(171,290)** | (281,745) |

- **Net debt**

Bonavista has calculated net debt based on the bank credit facility and senior unsecured notes, net of working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities).

Bonavista considers net debt to be a key measure in assessing the liquidity of the Corporation on a comparable basis with prior periods. Bonavista has calculated net debt based on the bank credit facility and senior unsecured notes, net of working capital. Working capital has been adjusted to exclude the current portion of financial instrument commodity contracts and the current portion of decommissioning liabilities. Management has excluded the current portion of financial instrument commodity contracts as they are subject to a high degree of volatility prior to ultimate settlement. Similarly, management has excluded the current portion of the decommissioning liability as this is an estimate based on management's assumptions and subject to volatility based on changes in cost and timing estimates, the risk-free discount rate and inflation rate.

The following table provides a reconciliation between the non-GAAP measure of net debt to the most directly comparable GAAP measure of long-term debt:

| | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Long-term debt | **801,625** | 800,544 |
| Working capital[(1)] | **(8,545)** | 29,425 |
| Current assets | | |
| Financial instrument commodity contracts | **57,192** | 64,496 |
| Current liabilities | | |
| Financial instrument commodity contracts | **(2,663)** | (38,146) |
| Decommissioning liabilities | **(11,704)** | (16,146) |
| Net debt | **835,905** | 840,173 |

Note:

(1) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million. Current assets as at December 31, 2017 were $152.6 million compared to current liabilities of $182.1 million.

- **Payout ratio**

  Payout ratio is equal to net capital expenditures, decommissioning expenditures and dividends declared, divided by adjusted funds flow.

  The payout ratio is a key cash flow measure that is used by management to determine the sustainability of Bonavista's dividend and capital expenditure program.

  The below table provides a reconciliation between cash flow from operating activities, the most comparable GAAP measure, to the measure of adjusted funds flow. Adjusted funds flow is the denominator in the calculation of the payout ratio which is then calculated below.

| | Three months ended December 31, | | Year ended December 31, | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands) | | | | |
| Cash flow from operating activities | **77,581** | 94,515 | **291,191** | 325,619 |
| Interest expense(1) | **(8,553)** | (8,953) | **(35,141)** | (38,118) |
| Decommissioning expenditures | **2,198** | 5,746 | **12,318** | 17,318 |
| Changes in non-cash working capital(2) | **(10,151)** | (5,200) | **(8,773)** | (2,831) |
| Adjusted funds flow | **61,075** | 86,108 | **259,595** | 301,988 |
| Dividends declared | **2,555** | 2,518 | **10,168** | 10,040 |
| Net capital expenditures | **56,430** | 57,657 | **171,290** | 281,745 |
| Decommissioning expenditures | **2,198** | 5,746 | **12,318** | 17,318 |
| Total | **61,183** | 65,921 | **193,776** | 309,103 |
| Divided by Adjusted funds flow | **61,075** | 86,108 | **259,595** | 301,988 |
| Payout ratio(3) | **100%** | 77% | **75%** | 102% |

Notes:

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) Refer to note 10, "Supplemental Cash Flow Information", of the financial statements.
(3) Bonavista's payout ratio in prior disclosure documents excluded decommissioning expenditures from the numerator, this has been amended to better reflect a measure of sustainability.

## OIL AND GAS ADVISORIES

Reference has been made to the following oil and gas terms "finding and development costs" ("F&D costs") and "finding, development and acquisition costs" ("FD&A costs"), "F&D recycle ratio", "FD&A recycle ratio" and "reserve life index" ("RLI") which have been prepared by management and do not have standardized meanings or standard calculations and therefore such measures may not be comparable to similar measures used by other entities. These terms are used by Bonavista's management to measure the success of replacing reserves and to compare operating performance to previous periods on a comparable basis. For additional information on these measures reference should be made to Bonavista's Annual Information Form which is available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

- Finding and development costs ("F&D costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.
- Finding, development and acquisition costs ("FD&A costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category. Both finding and development costs and finding, development and acquisition costs take into account reserve revisions during the year on a per boe basis.
- The F&D recycle ratio is calculated by dividing the operating netback(1) per boe for the period by the F&D costs per boe for the particular reserve category.
- The FD&A recycle ratio is calculated by dividing the operating netback(1) per boe for the period by the FD&A costs per boe for the particular reserve category.
- The reserve life index is calculated based on the amount for the relevant reserve category divided by the production forecast as prepared by Bonavista's reserve engineers GLJ.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

Cost to add production is determined by dividing the yearly capital exploration and development expenditures by the year-end production adds. The year-end production adds are determined by subtracting the current year exit production from the prior year exit production, adjusted for any acquisition or disposition volumes, added to the base yearly decline volumes.

The estimated net asset value is based on the estimated net present value of all future net revenue from Bonavista's proved plus probable reserves, discounted at 10%, before tax, as estimated by GLJ, at year-end, with and without the estimated value of Bonavista's undeveloped acreage and net debt. Common share values in Bonavista's net asset value per share metric are calculated by including outstanding common shares and exchangeable shares which are converted into common shares on certain terms and conditions.

Any reference to value capital, support capital and production efficiency have been prepared by management and are used to measure performance. These terms do not have standardized meanings or standard calculations and are not comparable to similar measures used by other entities.

- Value capital includes expenditures on drilling, completion, equipping and tie-in projects and recompletions. Value capital has been used to define capital expenditures, included in exploration and development expenditures, that are directly associated with generating incremental reserves and cash flow from operating activities.
- Support capital includes expenditures on land, facilities and infrastructure and workovers  and facilities. Support capital has been used to define capital expenditures, included in exploration and development expenditures, that are associated with maintenance existing operations and to support future development.
- Production efficiency which is defined as a type of capital efficiency that measures the cost to add an incremental barrel of flowing production. Specifically, for the average production efficiencies of our plays, Bonavista uses the total actual/projected drill, complete and tie-in capital divided by the total of the wells' initial production rate.

Any reference made in this document to initial production rates are useful in confirming the presence  of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue  production and decline thereafter. While encouraging, readers are caution not to place reliance on such rates in calculating the aggregate production for Bonavista.

Certain information in this document may constitute "analogous information" as defined in NI 51-101 with respect to offset well production and drilling results from other producers with operations that are in geographical proximity to or believed to be on-trend with Bonavista's assets. Management of Bonavista believes the information may be relevant to help determine the expected results that Bonavista may achieve within Bonavista's lands and such information has been presented to help demonstrate the basis for Bonavista's business plans and strategies. There is no certainty that the results of the analogous information or inferred thereby will be achieved by Bonavista and such information should not be construed as an estimate of future production levels, reserves or the actual characteristics and quality of Bonavista's assets.

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

### *FORWARD-LOOKING STATEMENT ADVISORIES*

This document contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words “anticipate”, “expect”, “project”, “plan”, “estimate”, “budget”, “will”, “strategy”, “ongoing”, “potential”, “believe”, “continue" and similar expressions are intended to identify forward-looking information.  Any "financial outlook" or "future orientated financial information" in the document as defined by applicable securities laws, has been approved by the management of Bonavista. Such financial outlook or future orientated financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

In particular, but without limiting the foregoing, this document contains forward-looking information and statements pertaining to the following:

- the Corporation's focus and plans to create maximum shareholder value;
- expectations regarding Bonavista's financial flexibility in the future;
- expectations regarding the quality, predictability, resilience and sustainability of Bonavista's asset base;
- the performance characteristics of Bonavista's oil and natural gas properties;
- expectations regarding industry conditions, future commodity prices and demand for natural gas;
- the Corporation's 2019 capital expenditure budget;
- the Corporation's exploration and development plans and the results therefrom;
- the ability of the Corporation to be agile in responding to changes to commodity prices;
- expectations for 2019 for production volumes, adjusted funds flow, net debt and payout ratio;
- expectations of future production rates, volumes and production mixes;
- projections of market prices and costs, and exchange and inflation rates;
- the Corporation's plans to reduce Bonavista's net debt to strengthen the balance sheet and enhance future financial flexibility;
- expectations that Bonavista will generate adjusted funds flow in excess of what is required to maintain our forecasted production volumes;
- expectations of future ethane rejection and anticipated production curtailments;
- expectations regarding reserves volumes, reserve values, reserve life index, future development costs and decline rates;
- the Corporation's acquisition and infrastructure plans;

- the benefits to be obtained from Bonavista's natural gas marketing strategy;
- expectations that investments in crown land acquisitions and infrastructure will add value beyond 2018;
- expectations regarding the number and quality of Bonavista's undeveloped locations;
- expectations regarding Bonavista's future decommissioning expenditures;
- the Corporation's focus on creating incremental financial flexibility;
- expectations regarding Bonavista's quarterly dividend policy;
- the Corporation's plans to monitor the economic landscape, commodity prices and our drilling results and adjust capital spending levels as conditions warrant;
- the sources of funding Bonavista's abandonment and reclamation program, dividend payments and capital expenditures;
- the benefits of Bonavista's asset concentration strategy;
- the Corporation's risk management program and goals including its market diversification strategy and plans;
- the Corporation's estimated tax pools and expectations that future taxable income will be available to utilize accumulated tax pools; and
- the impact of certain future accounting policies on Bonavista's financial statements;

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

By their nature, forward-looking statements are subject to numerous risks and uncertainties; some of which are beyond Bonavista's control, including the impact of general economic assumptions and conditions, industry assumptions and conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental tax and royalty legislation, access to market, production curtailment and ethane rejection, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Bonavista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements or if any of them do so, what benefits that Bonavista will derive there from. Bonavista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

This document contains information from publicly available third party sources as well as industry data prepared by management on the basis of its knowledge of the industry in which Bonavista operates (including management's estimates and assumptions relating to the industry based on that knowledge). Management's knowledge of the oil and natural gas industry has been developed through its experience and participation in the industry. Management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but Bonavista has not independently verified the accuracy or completeness of this data. Third-party sources generally state that the information contained therein has been obtained from sources believed to be reliable, but Bonavista has not independently verified the accuracy or completeness of included information. Although management believes it to be reliable, Bonavista has not independently verified any of the data from third-party sources referred to in this document or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

BONAVISTA
ENERGY CORPORATION

## MANAGEMENT'S REPORT

The Consolidated Financial Statements of Bonavista Energy Corporation and related financial information were prepared by, and are the responsibility of Management. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards. The Consolidated Financial Statements and related financial information reflect amounts which must of necessity be based upon informed estimates and judgments of Management with appropriate consideration to materiality. The Corporation has developed and maintains systems of controls, policies and procedures in order to provide reasonable assurance that assets are properly safeguarded, and that the financial records and systems are appropriately designed and maintained, and provide relevant, timely and reliable financial information to Management.

The Consolidated Financial Statements have been audited by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

The Board of Directors has established an Audit Committee. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the Consolidated Financial Statements, and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the condensed consolidated interim financial statements prior to their release, as well as annually to review the Corporation's annual Consolidated Financial Statements and Management's Discussion and Analysis and to recommend their approval to the Board of Directors.

The external auditors have unrestricted access to the Corporation, the Audit Committee and the Board of Directors.

Jason E. Skehar
President and Chief Executive Officer

Dean M. Kobelka
Vice President, Finance and Chief Financial Officer

February 14, 2019
Calgary, Alberta

## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bonavista Energy Corporation

***Opinion***

We have audited the consolidated financial statements of Bonavista Energy Corporation (the “Company”), which comprise:

- the consolidated statements of financial position as at December 31, 2018 and December 31, 2017
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

  (Hereinafter referred to as the “financial statements”).

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018 and December 31, 2017, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (“IFRS”).

***Basis for Opinion***

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the “*Auditors’ Responsibilities for the Audit of the Financial Statements*” section of our auditors’ report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

***Other Information***

Management is responsible for the other information. Other information comprises:

- the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors’ report thereon, included in the 2018 Annual Report.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions and the 2018 Annual Report as at the date of this auditors’ report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors’ report.

We have nothing to report in this regard.

***Responsibilities of Management and Those Charged with Governance for the Financial Statements***

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, 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.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

***Auditors' Responsibilities for the Audit of the Financial Statements***

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 14, 2019

## BONAVISTA ENERGY CORPORATION
Consolidated Statements of Financial Position

| **As at December 31** | **Note** | **2018** | 2017 |
|---|---|---|---|
| ($ thousands) | | | |
| **Assets** | | | |
| Current assets | | | |
| Accounts receivable | | **54,711** | 73,451 |
| Prepaid expenses and other assets | | **13,993** | 14,680 |
| Financial instrument commodity contracts | (6) | **57,192** | 64,496 |
| Financial instrument contracts | (6) | **1,200** | — |
| | | **127,096** | 152,627 |
| Financial instrument commodity contracts | (6) | **19,898** | 10,260 |
| Financial instrument contracts | (6) | **17,204** | — |
| Property, plant and equipment | (11) | **2,633,494** | 2,658,352 |
| Exploration and evaluation assets | (12) | **126,017** | 138,231 |
| Total assets | | **2,923,709** | 2,959,470 |
| **Liabilities and Shareholders' Equity** | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | | **101,629** | 125,242 |
| Current portion of decommissioning liabilities | (15) | **11,704** | 16,146 |
| Dividends payable | | **2,555** | 2,518 |
| Financial instrument commodity contracts | (6) | **2,663** | 38,146 |
| | | **118,551** | 182,052 |
| Financial instrument commodity contracts | (6) | **5,226** | 10,423 |
| Financial instrument contracts | (6) | **—** | 19,295 |
| Long-term debt | (14) | **801,625** | 800,544 |
| Other long-term liabilities | | **4,070** | 6,603 |
| Decommissioning liabilities | (15) | **419,042** | 393,180 |
| Deferred income taxes | (16) | **23,011** | 7,912 |
| Total liabilities | | **1,371,525** | 1,420,009 |
| Shareholders' equity | (13) | | |
| Shareholders' capital | | **2,870,931** | 2,852,643 |
| Exchangeable shares | | **89,417** | 93,266 |
| Contributed surplus | | **53,168** | 56,531 |
| Deficit | | **(1,461,332)** | (1,462,979) |
| Total shareholders' equity | | **1,552,184** | 1,539,461 |
| Total liabilities and shareholders' equity | | **2,923,709** | 2,959,470 |

Commitments (note 17) and Subsequent events (note 6).

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors of Bonavista Energy Corporation,

Ian S. Brown, Director

Michael M. Kanovsky, Director

## BONAVISTA ENERGY CORPORATION

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

| For the years ended December 31 | Note | 2018 | 2017 |
|---|---|---|---|
| ($ thousands, except per share amounts) | | | |
| **Revenues** | | | |
| Production | (7) | **514,967** | 553,002 |
| Royalties | | **(34,360)** | (41,677) |
| Production revenues, net of royalties | | **480,607** | 511,325 |
| Financial instrument commodity contracts | | | |
| Realized gains on financial instrument commodity contracts | (6) | **16,083** | 25,566 |
| Unrealized gains on financial instrument commodity contracts | (6) | **43,014** | 107,614 |
| Production revenues, net of royalties and financial instrument commodity contracts | | **539,704** | 644,505 |
| **Expenses** | | | |
| Operating | | **143,935** | 147,165 |
| Transportation | | **33,728** | 24,871 |
| General and administrative | | **24,291** | 24,749 |
| Share-based compensation | (13) | **10,381** | 15,702 |
| Loss (gain) on disposition of property, plant and equipment | (11) | **6,725** | (13,589) |
| Gain on disposition of exploration and evaluation assets | (11) | **(167)** | (976) |
| Depletion, depreciation, amortization and impairment | (11) | **227,447** | 469,555 |
| Net finance costs | (9) | **66,450** | 21,209 |
| Total expenses | | **512,790** | 688,686 |
| Income (loss) before taxes | | **26,914** | (44,181) |
| Deferred income tax expense (recovery) | (16) | **15,099** | (16,251) |
| Net income (loss) and comprehensive income (loss) | | **11,815** | (27,930) |
| Net income (loss) per share | | | |
| Basic | (13) | **0.05** | (0.11) |
| Diluted | (13) | **0.04** | (0.11) |

See accompanying notes to the consolidated financial statements.

## BONAVISTA ENERGY CORPORATION
Consolidated Statements of Changes in Equity

| ($ thousands) | Shareholders' Capital | Exchangeable Shares | Contributed Surplus | Deficit | Total Shareholders' Equity |
|---|---|---|---|---|---|
| Balance as at December 31, 2016 | 2,837,945 | 93,859 | 53,449 | (1,425,009) | 1,560,244 |
| Net loss | — | — | — | (27,930) | (27,930) |
| Conversion of restricted incentive and performance incentive awards | 13,994 | — | (13,994) | — | — |
| Tax effect on conversion of restricted incentive and performance incentive awards | 111 | — | — | — | 111 |
| Share-based compensation expense | — | — | 15,702 | — | 15,702 |
| Share-based compensation capitalized | — | — | 1,374 | — | 1,374 |
| Exchangeable shares exchanged for common shares | 593 | (593) | — | — | — |
| Dividends declared | — | — | — | (10,040) | (10,040) |
| Balance as at December 31, 2017 | 2,852,643 | 93,266 | 56,531 | (1,462,979) | 1,539,461 |
| Net income | **—** | **—** | **—** | **11,815** | **11,815** |
| Conversion of restricted incentive and performance incentive awards | **14,439** | **—** | **(14,439)** | **—** | **—** |
| Share-based compensation expense | **—** | **—** | **10,381** | **—** | **10,381** |
| Share-based compensation capitalized | **—** | **—** | **695** | **—** | **695** |
| Exchangeable shares exchanged for common shares | **3,849** | **(3,849)** | **—** | **—** | **—** |
| Dividends declared | **—** | **—** | **—** | **(10,168)** | **(10,168)** |
| Balance as at December 31, 2018 | **2,870,931** | **89,417** | **53,168** | **(1,461,332)** | **1,552,184** |

See accompanying notes to the consolidated financial statements.

## BONAVISTA ENERGY CORPORATION
Consolidated Statements of Cash Flows

| For the years ended December 31 | Note | 2018 | 2017 |
|---|---|---|---|
| ($ thousands) | | | |
| **Cash provided by (used in):** | | | |
| **Operating Activities** | | | |
| Net income (loss) | | **11,815** | (27,930) |
| Adjustments for: | | | |
| Depletion, depreciation, amortization and impairment | | **227,447** | 469,555 |
| Share-based compensation | | **10,381** | 15,702 |
| Unrealized gains on financial instrument commodity contracts | | **(43,014)** | (107,614) |
| Loss (gain) on disposition of property, plant and equipment | | **6,725** | (13,589) |
| Gain on disposition of exploration and evaluation assets | | **(167)** | (976) |
| Net finance costs | | **66,450** | 21,209 |
| Deferred income tax expense (recovery) | | **15,099** | (16,251) |
| Decommissioning expenditures | | **(12,318)** | (17,318) |
| Changes in non-cash working capital items | (10) | **8,773** | 2,831 |
| Cash flow from operating activities | | **291,191** | 325,619 |
| **Financing Activities** | | | |
| Dividends paid | | **(10,131)** | (10,015) |
| Interest paid | | **(32,951)** | (39,344) |
| Net repayment of long-term debt | | **(60,015)** | (79,464) |
| Cash flow used in financing activities | | **(103,097)** | (128,823) |
| **Investing Activities** | | | |
| Exploration and development | | **(164,492)** | (289,029) |
| Property acquisitions | | **(32,654)** | (13,736) |
| Property dispositions | | **26,616** | 21,577 |
| Office equipment | | **(760)** | (557) |
| Changes in non-cash working capital items | (10) | **(16,804)** | (1,028) |
| Cash flow used in investing activities | | **(188,094)** | (282,773) |
| **Change in cash** | | **—** | (85,977) |
| **Cash, beginning of year** | | **—** | 85,977 |
| **Cash, end of year** | | **—** | — |

See accompanying notes to the consolidated financial statements.

## 1. Structure of the Corporation

The principal undertakings of Bonavista Energy Corporation (the “Corporation” or “Bonavista”) are to carry on the business of acquiring, developing and holding interests in natural gas, natural gas liquids and oil properties and assets in Western Canada.

Bonavista's principal place of business is located at 1500, 525 - 8th Avenue SW, Calgary, Alberta, Canada T2P 1G1.

*The audited consolidated financial statements of the Corporation as at and for the year ended December 31, 2018, are available on SEDAR at www.sedar.com or can be obtained from Bonavista’s website at www.bonavistaenergy.com.*

## 2. Basis of presentation

### Statement of compliance

The consolidated financial statements (the "financial statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). A summary of Bonavista's significant accounting policies under IFRS are presented in note 4, "Significant accounting policies". These accounting policies have been applied consistently for all periods presented in these financial statements, with the exception of the impact from the adoption of new accounting standards on January 1, 2018 as described in note 3, "Changes in accounting policies".

These financial statements were authorized for issue by the Corporation's Board of Directors' on February 14, 2019.

### Basis of measurement

These financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value.

### Functional and presentation currency

These financial statements are presented in Canadian dollars ("CDN"), which is the Corporation's functional currency.

### Use of management's judgments and estimates

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Bonavista's operating environment changes.

Estimates and underlying assumptions are reviewed on an ongoing basis by management. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The key sources of estimation uncertainty to the carrying amounts of assets and liabilities are discussed below:

i. Determination of a Cash-Generating Unit (“CGU”)

   The determination of Bonavista’s CGUs is subject to management’s judgment. In determining Bonavista’s CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. On December 31, 2018, the Corporation re-aligned certain cash-generating units to be consistent with the operations of Bonavista's current asset base by combining the Central Alberta CGU and South Central Alberta CGU to form the West Central CGU. Bonavista's current CGU composition includes its British Columbia CGU, Deep Basin CGU and West Central CGU.

ii. Impairment testing

   Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less costs of disposal and value in use and is subject to management estimates. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

At December 31, 2018, Bonavista evaluated each of its CGUs for indicators of potential impairment or a reversal of previously recorded impairment charges. Key estimates used in the determination of cash flows used to calculate the recoverable amount of a CGU include: quantities of reserves and future production; future commodity pricing; development costs; operating costs; royalty obligations; and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU. Bonavista identified indicators of impairment at December 31, 2018 as a result of a sustained decline in forward commodity benchmark prices for natural gas. As such impairment tests were conducted on each of Bonavista's CGUs at December 31, 2018, refer to note 11, "Property, Plant and Equipment". Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

iii. Proved plus probable oil and natural gas reserves

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income, as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments or reversals.

iv. Depreciation, depletion, amortization and impairment

Property, plant and equipment is measured at cost less accumulated depreciation, depletion, amortization and impairment. Bonavista's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved and probable reserves.

v. Decommissioning liability

The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions.

vi. Financial instrument contracts

The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation's financial instrument contracts are subject to changes in foreign exchange rates.

## 3. Changes in accounting policies

### a. Adoption of IFRS 9, "Financial Instruments"

Effective January 1, 2018, Bonavista adopted IFRS 9 *Financial Instruments* ("IFRS 9"), which replaced IAS 39 *Financial Instruments: Recognition and Measurement* ("IAS 39"). The retrospective adoption of IFRS 9 did not have a material impact on the Corporation's financial statements. The nature and effects of the key changes to Bonavista's accounting policies resulting from the adoption of IFRS 9 are summarized below.

***Classification of Financial Assets and Financial Liabilities***

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. Under IFRS 9, derivatives embedded in contracts where the host is a financial asset in the scope of the standard are never separated. Instead, the hybrid financial instrument as a whole is assessed for classification. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of Bonavista's financial assets and financial liabilities.

| | Measurement Category | |
|---|---|---|
| **Financial Instrument** | **IAS 39** | **IFRS 9** |
| Cash and cash equivalents | loans and receivables | amortized cost |
| Accounts receivable | loans and receivables | amortized cost |
| Financial instrument commodity contracts | fair value through profit or loss | fair value through profit or loss |
| Financial instrument contracts | fair value through profit or loss | fair value through profit or loss |
| Accounts payable and accrued liabilities | financial liabilities measured at amortized cost | amortized cost |
| Dividends payable | financial liabilities measured at amortized cost | amortized cost |
| Long-term debt | financial liabilities measured at amortized cost | amortized cost |

There were no adjustments to the carrying amounts of Bonavista's financial instruments as a result of the change in classification from IAS 39 to IFRS 9. Bonavista has not designated any financial instruments as FVOCI, nor does the Corporation apply hedge accounting.

***Impairment of Financial Assets***

IFRS 9 replaces the “incurred loss” model in IAS 39 with an “expected credit loss” model. The new impairment model applies to financial assets measured at amortized cost, and contract assets and debt investments measured at FVOCI. Under IFRS 9, credit losses will be recognized earlier than under IAS 39. The application of the new expected credit loss model did not have a material impact on Bonavista's financial assets. As at December 31, 2018, the majority of Bonavista's receivables were from oil and natural gas marketers which are normally collected by Bonavista on the 25$^{th}$ of the month following production and the remaining receivables were from joint operations partners. As the operator of properties, Bonavista has the ability in most instances to withhold production from joint operations partners, in default of amounts owing.

**b. Adoption of IFRS 15, "Revenue from Contracts with Customers"**

IFRS 15 *Revenue from Contracts with Customers* (“IFRS 15”) was issued by the IASB in May of 2014 and replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations effective for reporting periods beginning on or after January 1, 2018. IFRS 15 specifies how and when an IFRS reporter will recognize revenue as well as requiring more informative, relevant disclosures. The new standard provides a single, principles-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The new standard only affects contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRSs.

Bonavista adopted IFRS 15 effective January 1, 2018. Bonavista applied IFRS 15 to all of its contracts with customers using the cumulative effect method. Under this method, prior period financial statements have not been restated. Bonavista’s management reviewed its revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to its net income or in the timing of when production revenue is recognized. As a result, no adjustments were required in the January 1, 2018 opening statement of financial position. The adoption of IFRS 15 does however result in new disclosure requirements contained in note 7, "Revenues" of the financial statements.

## 4. Significant accounting policies

### Basis of consolidation

The consolidated financial statements comprise the financial statements of Bonavista and its subsidiaries as at December 31, 2018. Subsidiaries are consolidated from the date of acquisition, being the date on which Bonavista obtains control, and continues to be consolidated until the date that control ceases. Control exists when Bonavista has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. All intercompany balances and transactions, and any unrealized income and expenses, arising from intercompany transactions are eliminated in full.

Many of Bonavista's oil and natural gas activities involve jointly controlled assets. The financial statements include Bonavista's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

### Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated at the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in the consolidated statement of income (loss).

### Financial instruments

Financial instruments are recognized when Bonavista becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are offset and the net amount is presented in the consolidated statement of financial position when, and only when, Bonavista has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

### Classification and Measurement of Financial Assets

The initial classification of a financial asset depends on Bonavista's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which Bonavista classifies its financial assets:

- Amortized cost - Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flow that represent solely payments of principal and interest;
- Fair value through other comprehensive income ("FVOCI") - Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or

- Fair value through profit or loss ("FVTPL") - Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial assets.

Bonavista initially recognizes loans, receivables and deposits on the date that they originated. All other financial assets (including assets designated at fair value through profit or loss) are recognized initially on the date at which Bonavista becomes a party to the contractual provisions of the instrument.

Bonavista derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by Bonavista is recognized as a separate asset or liability.

*Impairment of financial assets*

Bonavista recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, Bonavista measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

**Classification and Measurement of Financial Liabilities**

Bonavista initially recognizes debt securities issued and subordinated liabilities on the date that they originated. All other financial liabilities (including liabilities designated at FVTPL) are recognized initially on the trade date at which Bonavista becomes a party to the contractual provisions of the instrument.

Bonavista initially classifies financial liabilities as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable. Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in the consolidated statement of income (loss). Other financial liabilities are initially measured at fair value less attributable transaction costs and are subsequently measured at amortized cost using the effective interest method.

Bonavista derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired. Any gain or loss on derecognition is recognized in the consolidated statement of income (loss).

**Derivative financial instruments**

Bonavista has entered into certain derivative financial instruments to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange rates. These derivative financial instruments are not used for trading or speculative purposes. Bonavista has not designated its derivative financial instruments as effective accounting hedges, and thus has not applied hedge accounting, even though the Corporation considers all commodity contracts and foreign exchange contracts to be economic hedges. Derivative financial instruments are classified and measured at FVTPL and any attributable transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivative financial instruments are measured at fair value, and changes therein are recognized immediately in profit or loss. The estimated fair value of all derivative financial instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

Bonavista has accounted for its forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery, of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the consolidated statement of financial position. Settlements on these physical sales contracts are recognized in production revenues.

**Exploration and evaluation assets and property, plant and equipment**

*Exploration and evaluation expenditures*

Exploration and evaluation (“E&E”) costs, including the costs of acquiring licences and directly attributable general and administrative costs are initially capitalized as either tangible or intangible E&E assets according to the nature of the assets acquired. Pre-licence costs are recognized in the consolidated statement of income (loss) as incurred. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when total proved plus probable reserves are determined to exist. Annually, a review of each exploration licence or field is carried out, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, intangible E&E assets attributable to those reserves are transferred from E&E assets to a separate category within tangible assets referred to as oil and natural gas properties.

Gains and losses on dispositions of exploration and evaluation assets, are determined by comparing the proceeds from disposal with the carrying amount of exploration and evaluation assets and are recognized on a net basis within “gain (loss) on disposition of exploration and evaluation assets” in the consolidated statement of income (loss).

*Development and production costs*

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of income (loss) as incurred.

Gains and losses on dispositions of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized on a net basis within “gain (loss) on disposition of property, plant and equipment” in the consolidated statement of income (loss).

**Depletion, depreciation and amortization**

The net carrying amount of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved plus probable reserves are estimated using independent reserve engineering reports and represent the estimated quantities of oil, natural gas liquids and natural gas, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved plus probable and a 50% statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proved plus probable reserves are 90% and 10%, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered total proved plus probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes: (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved plus probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

| | |
|---|---|
| Facilities | 15 years |
| Oil and natural gas properties | Based on CGU Reserve Life |

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that Bonavista will obtain ownership by the end of the lease term. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

The estimated useful lives for other assets for the current and comparative years are as follows:

| | |
|---|---|
| Office equipment | 5 years |
| Fixtures and fittings | 5 years |
| Leaseholds | 9.5 years |

Other intangible assets that are acquired by Bonavista, which have finite useful lives, are measured at cost less accumulated amortization and accumulated impairment losses. Subsequent expenditure is capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of other intangible assets, other than goodwill, from the date they were available for use.

### Impairment

*Exploration and evaluation ("E&E") assets*

E&E assets are assessed for impairment at the operating segment level and tested for impairment when circumstances arise which could indicate potential impairment. Upon determination of technical feasibility and commercial viability, the E&E assets are first tested for impairment by comparing the carrying amount to the greater of the E&E assets' fair value less cost of disposal or value in use and then transferred to a separate category within tangible assets referred to as oil and natural gas properties. An impairment charge on E&E assets is recognized if the carrying value of the E&E assets exceeds the recoverable amount. Any impairment charge is recognized in the consolidated statement of income (loss) in depletion, depreciation, amortization and impairment.

If there is an indication that a previously recognized impairment charge may no longer exist or may have decreased, the recoverable amount of the relevant E&E asset is calculated and compared against the carrying amount. An impairment charge is reversed to the extent that the asset's recoverable amount does not exceed the carrying amount that would have been determined if no impairment charge had been recognized.

*Development and production assets*

For the purpose of impairment testing, Bonavista's development and production assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, the CGU. CGUs are reviewed at each reporting date to determine whether there is any indication of impairment or impairment reversals. If any such indication exists, an impairment test is performed by comparing the CGUs carrying value to its recoverable amount, defined as the greater of a CGU's fair value less costs of disposal and value in use. Any excess of carrying value over the recoverable amount is recognized in the consolidated statement of income (loss) in depletion, depreciation, amortization and impairment.

If there is an indication that a previously recognized impairment charge may no longer exist or may have decreased, the recoverable amount of the relevant CGU is calculated and compared against the carrying amount. An impairment charge is reversed to the extent that the asset's recoverable amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment charge had been recognized. A reversal of an impairment charge is recognized in the consolidated statement of income (loss) in depletion, depreciation, amortization and impairment.

### Employee benefits

*Share-based compensation*

Long-term incentives are granted to officers, directors, employees and certain consultants in accordance with Bonavista's restricted incentive award and performance incentive award plans.

The fair value of restricted incentive awards is assessed on the grant date factoring in the weighted average trading price of the five days preceding the grant date and forecasted dividends. This fair value is recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon the conversion of the restricted incentive awards or the settlement of the incentive awards by common shares, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital. Restricted incentive awards vest on terms up to three years from the initial date of grant as determined by Bonavista's Board of Directors.

The fair value of performance incentive awards is assessed on grant date by using the closing price of common shares and multiplied by the estimated performance multiplier. The performance multiplier can range from 0 to 2 and is dependent on the performance of the Corporation at the end of the vesting period relative to corporate performance measures determined at the discretion of Bonavista's Board of Directors. The fair value is recognized as compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon settlement of the performance incentive awards by common shares, on the predetermined payment date, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital. Performance incentive awards vest thirty-nine months from the initial date of grant as determined by Bonavista's Board of Directors.

Under the long-term incentive plans, forfeiture rates are assigned at the grant date and upon vesting, the difference between estimated and actual forfeitures is adjusted through share-based compensation.

*Short-term employee benefits*

Short-term employee benefit obligations are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short-term cash bonus or profit-sharing plans if Bonavista has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

### Lease payments

Payments made under operating leases are recognized in profit and loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

### Provisions

A provision is recognized if, as a result of a past event, Bonavista has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

### Decommissioning liabilities

Bonavista's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management’s best estimate of expenditure required to settle the present obligation at the date of the consolidated statement of financial position. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

### Revenues

Bonavista’s production revenues from the sale of crude oil, natural gas liquids and natural gas are based on the consideration specified in contracts with customers. Bonavista recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract.

Bonavista evaluates its arrangements with third parties and partners to determine if Bonavista is acting as the principal or as an agent. Bonavista is considered the principal in a transaction when it has primary responsibility for the transaction. If Bonavista acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by Bonavista from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Bonavista are evaluated by management to determine if they originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

### Finance income and costs

Finance costs comprise of interest expense on borrowings, unwinding of the discount on provisions and impairment losses recognized on financial assets. Fair value losses on financial assets are recognized in the consolidated statement of income (loss).

Interest income is recognized as it accrues in the consolidated statement of income (loss), using the effective interest method.

Foreign currency gains and losses are reported under finance income or expenses.

### Income taxes

Income tax expense comprises current and deferred income taxes. Current and deferred income taxes are recognized in the consolidated statement of income (loss) except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income (loss).

Current tax is the expected tax payable or receivable on the taxable income or loss for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are not recognized for:

- temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss;
- temporary differences related to investments in subsidiaries to the extent that it is probable that they will not reverse in the foreseeable future; and
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

Deferred income tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

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

### Per share amounts

Basic per share amounts are calculated by dividing net income (loss) attributable to common shareholders of Bonavista by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting net income (loss) attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as stock options, restricted incentive awards and performance incentive awards granted to employees.

## 5. Future accounting policies

Below is a description of a new IFRS standard that is not yet effective and has not been applied in the preparation of the financial statements. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material impact on Bonavista's financial statements.

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces IAS 17 *Leases*. The new standard introduces a single recognition and measurement model for leases, which requires the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. The new standard is to be adopted either retrospectively or using a modified retrospective approach. Bonavista intends to adopt IFRS 16 in its financial statements for the period beginning on January 1, 2019, using the modified retrospective transition approach. The Corporation is currently in the process of quantifying the impact of the contracts that fall within the scope of the new standard. The Corporation expects adjustments for its office lease, certain vehicles and certain field equipment, however, the full extent of the impact has not yet been finalized.

## 6. Financial risk management

To manage its exposure to certain market risks, Bonavista has a risk management program in place which includes financial instruments as disclosed in the commodity price risk and foreign exchange risk sections of this note. The objective of Bonavista's risk management program is to mitigate exposure to fluctuations in commodity prices, interest rates and foreign exchange rates to reduce volatility in the Corporation's adjusted funds flow as defined in note 8, "Capital management".

### Commodity price risk

Bonavista is exposed to commodity price risk as prices received for its natural gas, natural gas liquids and oil production fluctuate. Commodity prices fluctuate as a result of a number of local and global factors including, supply and demand, inventory levels, weather patterns, pipeline transportation constraints, political stability and economic factors. Bonavista mitigates a portion of the commodity price risk through the use of various financial instrument commodity contracts and physical delivery sales contracts. Bonavista's policy is to enter into commodity price contracts when considered appropriate to a maximum of 70% of forecasted revenues, net of royalties for the subsequent twelve month period, 60% in years two and three and 25% in years four and five, provided that no more than 80% of forecasted revenues, net of royalties, from any one product (where natural gas and ethane are considered as one product, propane is considered to be its own product and butane, condensate and oil are considered one product) may be hedged, or in the case of electricity, 60% of Bonavista's forecasted net consumption. The term of any commodity hedge executed will be limited to no more than five calendar years subsequent to the current calendar year. Bonavista's management regularly reviews this policy to reflect changes in market conditions.

### Financial instrument commodity contracts

At December 31, 2018, Bonavista had entered into the following costless collars to sell oil and natural gas:

| Volume | | Average Price | Contract | Term |
|---|---|---|---|---|
| **Natural gas** | | | | |
| 15,000 | gjs/d | CDN $2.30 - CDN $2.77 | AECO - Costless Collar | January 1, 2019 - March 31, 2019 |
| **Oil contracts** | | | | |
| 500 | bbls/d | CDN $80.00 - CDN $93.00 | WTI - Costless Collar | January 1, 2019 - December 31, 2019 |
| 500 | bbls/d | CDN $67.50 - CDN $ 73.01 | WTI - Costless Collar | January 1, 2019 - December 31, 2020 |

At December 31, 2018, Bonavista had entered into the following contracts to manage its overall commodity exposure:

| Volume | | Price | Contract | Term |
|---|---|---|---|---|
| **Natural gas** | | | | |
| 5,000 | gjs/d | CDN $3.05 | AECO - Swap | January 1, 2019 - March 31, 2019 |
| 60,000 | gjs/d | CDN $1.98 | AECO - Swap | April 1, 2019 - June 30, 2019 |
| 70,000 | gjs/d | CDN $1.42 | AECO - Swap | April 1, 2019 - October 31, 2019 |
| 40,000 | gjs/d | CDN $2.15 | AECO - Swap | April 1, 2019 - December 31, 2019 |
| 10,000 | gjs/d | CDN $2.00 | AECO - Swap | November 1, 2019 - March 31, 2020 |
| 10,000 | mmbtu/d | US ($1.00) | AECO - Basis Swap | January 1, 2019 - December 31, 2019 |
| 10,000 | mmbtu/d | US ($0.98) | AECO - Basis Swap | January 1, 2020 - December 31, 2021 |
| 15,000 | mmbtu/d | US ($0.08) | DAWN - Basis Swap | January 1, 2019 - December 31, 2019 |
| 15,000 | mmbtu/d | US ($0.08) | DAWN - Basis Swap | January 1, 2019 - December 31, 2021 |
| 5,000 | mmbtu/d | US $5.15 | VENTURA - Swap | January 1, 2019 - March 31, 2019 |
| 50,000 | mmbtu/d | US $3.04 | NYMEX - Swap | January 1, 2019 - December 31, 2019 |
| 10,000 | gjs/d | CDN $2.75 | AECO - Sold Call | January 1, 2019 - December 31, 2019 |
| 20,000 | gjs/d | CDN $2.13 | AECO - Sold Call | November 1, 2019 - March 31, 2020 |
| 10,000 | gjs/d | CDN $1.75 | AECO - Sold Call | January 1, 2020 - December 31, 2020 |
| 10,000 | gjs/d | CDN $1.80 | AECO - Sold Call | January 1, 2021 - December 31, 2021 |
| 10,000 | mmbtu/d | US $4.40 | NYMEX - Sold Call | January 1, 2019 - March 31, 2019 |
| 20,000 | mmbtu/d | US $3.02 | NYMEX - Sold Call | January 1, 2019 - December 31, 2019 |
| 10,000 | mmbtu/d | US $3.75 | NYMEX - Sold Call | January 1, 2019 - December 31, 2021 |

| Volume | | Price | Contract | Term |
|---|---|---|---|---|
| **Natural gas liquids** | | | | |
| 2,250 | bbls/d | US $33.18 | MTB BT - Swap | January 1, 2019 - December 31, 2019 |
| 1,200 | bbls/d | US $34.27 | MTB BT - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | US $35.75 | CNWY PN - Swap | January 1, 2019 - March 31, 2019 |
| 3,500 | bbls/d | US $26.84 | CNWY PN - Swap | January 1, 2019 - December 31, 2019 |
| 1,750 | bbls/d | US $28.59 | CNWY PN - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | US $26.04 | CNWY PN - Swap | January 1, 2020 - March 31, 2020 |
| **Oil** | | | | |
| 3,250 | bbls/d | CDN $72.28 | WTI - Swap | January 1, 2019 - December 31, 2019 |
| 750 | bbls/d | CDN $81.89 | WTI - Swap | January 1, 2020 - December 31, 2020 |
| 250 | bbls/d | CDN $80.17 | WTI - Swap | January 1, 2021 - December 31, 2021 |
| 1,000 | bbls/d | CDN $90.00 | WTI - Sold Call | January 1, 2020 - December 31, 2020 |
| 1,000 | bbls/d | US $54.60 | WTI - Sold Call | January 1, 2020 - December 31, 2020 |

Subsequent to December 31, 2018, Bonavista entered into the following contracts to manage its overall commodity exposure:

| Volume | | Price | Contract | Term |
|---|---|---|---|---|
| 27,500 | gjs/d | CDN $1.23 | AECO - Swap | April 1, 2019 - October 31, 2019 |
| 250 | bbls/d | US ($8.75) | MSW - Basis | March 1, 2019 - December 31, 2019 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2020 - October 31, 2020 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2021 - October 31, 2021 |
| 30,000 | mmbtu/d | US ($1.36) | AECO - Basis Swap | April 1, 2022 - October 31, 2022 |
| 20,000 | mmbtu/d | US ($0.16) | CHICAGO - Basis Swap | April 1, 2022 - October 31, 2022 |

Bonavista's financial instrument commodity contracts are sensitive to commodity price volatility. The following tables highlight the approximate impact that changes in the fair value of the financial instrument commodity contracts would have on net income (loss) at December 31, 2018 with changes to the underlying commodity prices.

| | **Commodity Price Sensitivity** | |
|---|---|---|
| ($ thousands) | | |
| | Increase $0.10 | Decrease $0.10 |
| Natural Gas Commodity Contracts | (6,391) | 6,391 |
| | Increase $1.00 | Decrease $1.00 |
| Natural Gas Liquids Commodity Contracts | (3,242) | 3,242 |
| | Increase $1.00 | Decrease $1.00 |
| Oil Commodity Contracts | (1,461) | 1,461 |

Financial instrument commodity contracts are recorded on the consolidated statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of income (loss) and comprehensive income (loss). At December 31, 2018, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $69.2 million (December 31, 2017 - $26.2 million, net asset) of which a net asset of $54.5 million (December 31, 2017 - $26.4 million, net asset) relates to financial instrument commodity contracts with term dates within one year and a net asset of $14.7 million (December 31, 2017 - $0.2 million, net liability) relates to financial instrument commodity contracts with term dates beyond one year. During the year ended December 31, 2018, a net gain of $59.1 million (December 31, 2017 - $133.2 million, net gain) was recorded on the consolidated statement of income (loss) and comprehensive income (loss), consisting of a realized gain of $16.1 million (December 31, 2017 - $25.6 million realized gain) and an unrealized gain of $43.0 million (December 31, 2017 - $107.6 million unrealized gain).

### Physical purchase and sale contracts

At December 31, 2018, Bonavista had entered into the following fixed price physical contract to sell natural gas:

| Volume | | Price | Term |
|---|---|---|---|
| 20,000 | gjs/d | CDN $2.25 | November 1, 2019 - March 31, 2020[(1)] |

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 20,000 gjs/d on the last trade date of each month for the duration of the contract.

### Foreign exchange risk

Bonavista is exposed to foreign currency fluctuations as natural gas, natural gas liquids and oil prices are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar natural gas, natural gas liquids and oil swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate.

To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments:

| Settlement date | Contract | Notional US$ | CDN$/US$ |
|---|---|---|---|
| 2019[(1)] | US$ purchased forward | $9,314,400 | 1.2288 |
| November 2, 2020 | US$ purchased forward | $160,000,000 | 1.3049 |
| October 25, 2021 | US$ purchased forward | $150,000,000 | 1.2991 |
| November 2, 2022 | US$ purchased forward | $50,000,000 | 1.3012 |
| May 23, 2023 | US$ purchased forward | $40,000,000 | 1.2974 |

(1) Settlement dates of varying notional amounts coincide with interest payments on US dollar denominated senior unsecured notes, including: April 25, May 2, May 23, October 25, November 2 and November 23 of 2019.

Bonavista's financial instrument contracts are sensitive to changes in the CDN dollar to the US dollar exchange rate. Holding all other variables constant, a $0.01 change in the forward forecast CDN$/US$ exchange rate at December 31, 2018 would have had an impact of approximately $3.5 million on net income (loss) (December 31, 2017 - $2.9 million).

The fair value recorded on the consolidated statement of financial position for these financial instrument contracts as at December 31, 2018 was a net asset of $18.4 million of which a net asset of $1.2 million relates to financial instrument contracts with term dates within one year and a net asset of $17.2 million relates to financial instrument contracts with term dates beyond one year. The fair value recorded on the consolidated statement of financial position for these financial instrument contracts as at December 31, 2017 was a net liability of $19.3 million of which all relates to financial instrument contracts with term dates beyond one year. For the year ended December 31, 2018, an unrealized gain of $37.7 million was recorded on the consolidated statement of income (loss) and comprehensive income (loss) (December 31, 2017 - $23.7 million unrealized loss).

### Interest rate risk

Bonavista is exposed to interest rate risk on any amount outstanding on its Canadian bank credit facility. Bonavista manages interest rate risk by having both fixed interest rates on senior unsecured notes and floating interest rates on outstanding bank debt.

### Credit risk

Credit risk is the risk of financial loss to Bonavista if a customer or counterparty to a financial instrument fails to meet its contractual obligation and arises, primarily from joint operations partners, oil and natural gas marketers and financial intermediaries. Bonavista's accounts receivable are with oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous oil and natural gas marketers under normal industry sale and payment terms. Bonavista routinely assesses the financial strength of its counterparties. Bonavista may be exposed to certain losses in the event of non-performance by counterparties to financial instrument contracts. Bonavista mitigates this risk by entering into transactions with highly rated financial institutions.

The majority of Bonavista's credit exposure on accounts receivable at December 31, 2018 pertains to accrued sales revenue for December 2018 production volumes. Receivables from oil and natural gas marketers are normally collected by Bonavista on the 25$^{th}$ of the month following production. Receivables with joint operations partners are typically collected within one to three months of the joint operations invoice being issued to the partner. At December 31, 2018 Bonavista’s receivables consisted of $43.5 million of receivables from oil and natural gas marketers of which substantially all has been collected subsequent to December 31, 2018 and $11.2 million from joint operations partners of which $2.7 million has been subsequently collected.

Bonavista routinely monitors the age of its receivables, investigating the issue behind past due amounts and reviewing the creditworthiness and collection history of the counterparty. Bonavista considers all amounts greater than 90 days to be past due. At December 31, 2018 Bonavista has $4.0 million in accounts receivable that is considered to be past due (December 31, 2017 - $4.6 million). Although these amounts have been outstanding for greater than 90 days, they are still deemed to be collectible. As the operator of properties, Bonavista does have the ability in most instances to withhold production from joint operations partners, who are in default of amounts owing. The lifetime ECL allowances related to Bonavista's receivables from oil and natural gas marketers and joint operations partners were nominal as at and for the periods ended December 31, 2018 and December 31, 2017.

### Liquidity risk

Liquidity risk is the risk that Bonavista will encounter difficulty in meeting obligations associated with its financial liabilities. Bonavista's financial liabilities consist of accounts payable and accrued liabilities, dividends payable, financial instruments contracts, bank debt and senior unsecured notes. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities, and capital expenditures. Bonavista processes invoices within a normal payment period.

Accounts payable and accrued liabilities have contractual maturities of less than one year. Dividends payable are declared on a quarterly basis and are dependent upon a number of factors including current and future commodity prices, foreign exchange rates, Bonavista’s commodity hedging program, current operations and future investment opportunities. Financial instrument contracts have contractual maturities of less than five years on all commodity contracts and range from four months to five years on foreign exchange contracts. Bonavista’s revolving bank credit facility, as outlined in note 14, "Long-term debt", may at the request of the Corporation with the consent of the lenders, be extended on an annual basis beyond the existing term. Bonavista also has a series of senior unsecured notes outstanding with fixed interest rates, as outlined in note 14, "Long-term debt", which range in maturities from November 2, 2020 to May 23, 2025. Bonavista also has provided for financial convents under both its bank credit facility and senior unsecured notes, the details of which are outlined in note 14, "Long-term debt". Bonavista also maintains and monitors a certain level of adjusted funds flow which is used to partially finance all operating, investing and capital expenditures.

### Financial instrument classification and measurement

Bonavista's financial instruments include accounts receivable, financial instrument commodity contracts, financial instrument contracts, accounts payable and accrued liabilities, dividends payable and long-term debt. Bonavista classifies the fair value of these financial instruments 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 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

Bonavista's financial instrument commodity contracts, financial instrument contracts, bank debt and senior unsecured notes are classified as Level 2 measurements. To estimate the fair value of these financial instruments Bonavista uses quoted market prices when available or fair-value estimates from third party valuation models that use observable market data. Bonavista does not have any recurring fair value measurements classified as Level 1 or Level 3. Bonavista does not have any financial assets or financial liabilities that are subject to offsetting arrangements.

The fair market value recorded on Bonavista's consolidated statement of financial position for financial instrument contracts was:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Current assets | | |
| Financial instrument commodity contracts[1] | **57,192** | 64,496 |
| Financial instrument contracts[1] | **1,200** | — |
| Long-term assets | | |
| Financial instrument commodity contracts[1] | **19,898** | 10,260 |
| Financial instrument contracts[1] | **17,204** | — |
| Current liabilities | | |
| Financial instrument commodity contracts[1] | **(2,663)** | (38,146) |
| Long-term liabilities | | |
| Financial instrument commodity contracts[1] | **(5,226)** | (10,423) |
| Financial instrument contracts[1] | **—** | (19,295) |
| Net asset | **87,605** | 6,892 |

(1) Level 2

The fair value of accounts receivable, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due to the short-term nature of those instruments. Borrowings under Bonavista's bank credit facility bear interest at a floating market rate and accordingly the fair market value approximates the carrying value. The fair market value of Bonavista's senior unsecured notes at December 31, 2018 was approximately $792.1 million (December 31, 2017 - $722.9 million), compared to a carrying amount of $790.7 million (December 31, 2017 - $730.4 million).

## 7. Revenues

Bonavista produces natural gas, natural gas liquids and crude oil from its assets in the Western Canadian Sedimentary Basin ("WCSB"). Bonavista sells its production pursuant to fixed-price or variable-price physical delivery contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, Bonavista is required to deliver fixed or variable volumes of natural gas, natural gas liquids or crude oil to the contract counterparty.

Production revenue is recognized when Bonavista gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of production revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Bonavista's efforts to transfer production and therefore the resulting revenue is allocated to the production delivered in the period to which the variability relates. Bonavista does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. Bonavista’s contracts with customers generally have a term of one year or less, whereby delivery takes place throughout the contract period. Production revenues are normally collected on the business day nearest the 25$^{th}$ day of the month following production.

Bonavista’s production revenues were primarily generated in its Deep Basin and West Central core areas located in Alberta. Bonavista's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous oil and natural gas marketers under customary industry sale and payment terms. Bonavista routinely assesses the financial strength of its counterparties. Of the production revenue, five percent resulted from fixed price contracts, with the remaining 95 percent from sales whereby the transaction price was based on the index price in the transaction month.

The following table presents Bonavista’s production revenues disaggregated by product:

| | **Year ended December 31,** | |
|---|---|---|
| | **2018** | 2017 |
| ($ thousands) | | |
| Production Revenues | | |
| Natural Gas | **236,333** | 294,777 |
| Natural Gas Liquids | **227,827** | 208,139 |
| Oil | **50,807** | 50,086 |
| Total Production Revenues | **514,967** | 553,002 |

| | Year ended December 31, | |
|---|---|---|
| | **2018** | 2017 |
| ($ thousands) | | |
| Natural Gas Liquids by Component | | |
| Ethane ($C_2$) | **9,227** | 16,734 |
| Propane ($C_3$) | **49,904** | 49,797 |
| Butane ($C_4$) | **49,763** | 41,529 |
| Pentanes plus and condensate ($C_{5+}$) | **118,933** | 100,079 |
| Total Natural Gas Liquids | **227,827** | 208,139 |

Under certain marketing arrangements Bonavista will transfer title of its natural gas production to a third party marketing company who will subsequently deliver the natural gas production to an end customer by utilizing Bonavista's pipeline capacity. In such instances Bonavista's pipeline capacity, for the specified contract term, has been assigned to the third party marketing company. This transportation revenue stream is presented within natural gas production revenue which is disaggregated in the below table by type:

| | Year ended December 31, | |
|---|---|---|
| | **2018** | 2017 |
| ($ thousands) | | |
| Natural Gas Production Revenue | **219,243** | 285,844 |
| Transportation Revenue | **17,090** | 8,933 |
| Total Natural Gas Production Revenue | **236,333** | 294,777 |

Included in accounts receivable at December 31, 2018 was $43.5 million (December 31, 2017 - $63.3 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. Changes in Bonavista’s accrued production revenues result from changes in its production and transaction prices. As at December 31, 2018, Bonavista did not have any contracts for the sale of its future production beyond one year in term.

## 8. Capital management

Bonavista's objectives when managing capital are to: (i) preserve financial flexibility which will allow it to execute on its Corporate strategy through expenditures on exploration and development activities; (ii) maintain a strong financial position to support investor, creditor and market confidence; and (iii) deploy capital to provide an appropriate return on investment to its shareholders. Bonavista manages its capital structure and makes adjustments to it in response to changes in economic conditions and the risk characteristics of its underlying natural gas, natural gas liquids and oil assets. This is accomplished by consistently aligning Bonavista's capital and dividend programs with adjusted funds flow. Adjusted funds flow is used by management to assess Bonavista's ability to generate the cash flow necessary to finance capital expenditures, expenditures on decommissioning liabilities, fund its dividend program and meet other financial obligations.

Bonavista considers its capital structure to include working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities), bank credit facility, senior unsecured notes and shareholders' equity. Bonavista monitors capital based on the ratio of net debt to adjusted funds flow (annualized current quarter). The ratio represents the time period it would take to pay off Bonavista's net debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio is calculated as net debt divided by adjusted funds flow for the most recent calendar quarter, annualized (multiplied by four). This ratio may increase at certain times as a result of acquisitions or low commodity prices. Bonavista considers net debt to be a key measure in assessing the liquidity of the Corporation on a comparable basis with prior periods. Bonavista has calculated net debt based on the bank credit facility and senior unsecured notes, net of working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities). As at December 31, 2018, Bonavista’s ratio of net debt to adjusted funds flow (fourth quarter annualized) was 3.4 to 1 (December 31, 2017 - 2.4 to 1).

To facilitate the management of this ratio, Bonavista prepares annual adjusted funds flow and capital expenditure budgets, which are updated as necessary, and are routinely reviewed and approved by Bonavista’s Board of Directors. The Corporation manages its capital structure and makes adjustments by continually monitoring its business conditions, including: the current economic conditions; the risk characteristics of Bonavista’s natural gas, natural gas liquids and oil assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence commodity prices and adjusted funds flow, such as quality and basis differentials, royalties, operating costs and transportation costs.

To maintain or adjust the capital structure, Bonavista considers: its forecasted ratio of net debt to forecasted adjusted funds flow while attempting to finance an acceptable capital expenditure program including acquisition opportunities; the current level of bank credit available from the Corporation's lenders; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; the monetization of financial instrument contracts; issuance of new equity if available on favourable terms; the size of the capital expenditure program; the size of its decommissioning expenditure program and the level of dividends payable to its shareholders. Bonavista shareholders' capital is not subject to external restrictions, however, the Corporation's bank credit facility and senior unsecured notes do contain financial covenants, refer to note 14, "Long-term debt".

The following table provides a reconciliation of cash flow from operating activities to adjusted funds flow:

| | **Three months ended December 31,** | | **Year ended December 31,** | |
|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 |
| ($ thousands) | | | | |
| Cash flow from operating activities | **77,581** | 94,515 | **291,191** | 325,619 |
| Interest expense[(1)] | **(8,553)** | (8,953) | **(35,141)** | (38,118) |
| Decommissioning expenditures[(4)] | **2,198** | 5,746 | **12,318** | 17,318 |
| Changes in non-cash working capital[(2)] | **(10,151)** | (5,200) | **(8,773)** | (2,831) |
| Adjusted funds flow[(3)] | **61,075** | 86,108 | **259,595** | 301,988 |

(1) Interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) Refer to note 10, "Supplemental cash flow information".
(3) Adjusted funds flow as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.
(4) The timing of when decommissioning expenditures are incurred is predominately at the discretion of Bonavista's management. However, there is a non-discretionary component that relates to compliance with regulatory requirements and abandonment and reclamation projects where Bonavista is not the operator. For the three months ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $0.6 million (December 31, 2017 - $1.3 million). Similarly, for the year ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $3.6 million (December 31, 2017 - $3.1 million).

The following table provides a reconciliation of long-term debt to net debt and the net debt to adjusted funds flow ratio:

| Net Debt to Adjusted Funds Flow | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Long-term debt | **801,625** | 800,544 |
| Working capital[(1)] | **(8,545)** | 29,425 |
| Current assets | | |
| Financial instrument commodity contracts | **57,192** | 64,496 |
| Current liabilities | | |
| Financial instrument commodity contracts | **(2,663)** | (38,146) |
| Decommissioning liabilities | **(11,704)** | (16,146) |
| Net debt[(2)] | **835,905** | 840,173 |
| Adjusted funds flow (fourth quarter annualized)[(2)] | **244,300** | 344,432 |
| Net debt to adjusted funds flow (fourth quarter annualized) (ratio)[(2)] | **3.4:1** | 2.4:1 |
| Adjusted funds flow[(2)] | **259,595** | 301,988 |
| Net debt to adjusted funds flow (ratio)[(2)] | **3.2:1** | 2.8:1 |

(1) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million. Current assets as at December 31, 2017 were $152.6 million compared to current liabilities of $182.1 million.
(2) The measure as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

## 9. Finance costs and income

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Finance costs | | |
| Accretion of decommissioning liabilities | **8,891** | 8,581 |
| Accretion of other liabilities | **843** | 1,066 |
| Amortization of debt issue costs | **754** | 841 |
| Interest on bank debt | **4,406** | 2,501 |
| Interest on notes payable | **30,735** | 35,617 |
| Realized loss on foreign exchange | **—** | 32,675 |
| Unrealized loss on foreign exchange | **60,342** | — |
| Unrealized loss on financial instrument contracts | **—** | 23,657 |
| Total finance costs | **105,971** | 104,938 |
| Finance income | | |
| Realized gain on foreign exchange | **(1,822)** | — |
| Unrealized gain on foreign exchange | **—** | (83,729) |
| Unrealized gain on financial instrument contracts | **(37,699)** | — |
| Total finance income | **(39,521)** | (83,729) |
| Net finance costs | **66,450** | 21,209 |

## 10. Supplemental cash flow information

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Cash provided by (used for): | | |
| Accounts receivable | **18,740** | (5,879) |
| Prepaid expenses and other assets | **586** | 2,393 |
| Accounts payable and accrued liabilities, net of interest accrual | **(27,357)** | 5,289 |
| | **(8,031)** | 1,803 |
| Related to: | | |
| Operating activities | **8,773** | 2,831 |
| Investing activities | **(16,804)** | (1,028) |
| | **(8,031)** | 1,803 |

## 11. Property, plant and equipment

| Cost | Oil and natural gas properties | Facilities | Other Assets | Total |
|---|---|---|---|---|
| ($ thousands) | | | | |
| Balance as at December 31, 2016 | 4,900,372 | 526,256 | 29,383 | 5,456,011 |
| Additions | 268,323 | 16,102 | 557 | 284,982 |
| Acquisitions | 5,614 | 1,677 | — | 7,291 |
| Transfers from exploration and evaluation assets | 24,269 | — | — | 24,269 |
| Changes in decommissioning liabilities | (12,293) | — | — | (12,293) |
| Dispositions | (40,737) | (6,030) | — | (46,767) |
| Balance as at December 31, 2017 | 5,145,548 | 538,005 | 29,940 | 5,713,493 |
| Additions | **149,349** | **9,311** | **760** | **159,420** |
| Acquisitions | **11,840** | **14,429** | **—** | **26,269** |
| Transfers from exploration and evaluation assets | **32,064** | **—** | **—** | **32,064** |
| Changes in decommissioning liabilities | **19,802** | **—** | **—** | **19,802** |
| Dispositions | **(63,506)** | **(1,448)** | **—** | **(64,954)** |
| Balance as at December 31, 2018 | **5,295,097** | **560,297** | **30,700** | **5,886,094** |
| **Depletion, depreciation, amortization and impairment** | | | | |
| Balance as at December 31, 2016 | (2,474,316) | (119,836) | (18,096) | (2,612,248) |
| Depletion, depreciation, amortization and impairment | (444,095) | (23,286) | (2,174) | (469,555) |
| Dispositions | 24,504 | 2,158 | — | 26,662 |
| Balance as at December 31, 2017 | (2,893,907) | (140,964) | (20,270) | (3,055,141) |
| Depletion, depreciation and amortization | **(201,471)** | **(23,381)** | **(2,595)** | **(227,447)** |
| Dispositions | **29,429** | **559** | **—** | **29,988** |
| Balance as at December 31, 2018 | **(3,065,949)** | **(163,786)** | **(22,865)** | **(3,252,600)** |
| **Carrying amount** | | | | |
| As at December 31, 2018 | **2,229,148** | **396,511** | **7,835** | **2,633,494** |
| As at December 31, 2017 | 2,251,641 | 397,041 | 9,670 | 2,658,352 |

For the year ended December 31, 2018, $5.2 million (December 31, 2017 - $5.6 million) of direct general and administrative expenses were capitalized. At December 31, 2018, future development costs of $1,509.7 million were included in Bonavista's depletion calculation (December 31, 2017 - $1,415.0 million).

During the year ended December 31, 2018, Bonavista disposed of certain non-core petroleum and natural gas rights and non-core properties for total proceeds of $26.6 million resulting in a before tax loss on sale of property, plant and equipment of $6.7 million and a $0.2 million before tax gain on sale of exploration and evaluation assets.

During the comparative year ended December 31, 2017, Bonavista disposed of certain non-core petroleum and natural gas rights and non-core properties for total proceeds of $21.6 million resulting in a before tax gain on sale of property, plant and equipment of $13.6 million and a $1.0 million before tax gain on sale of exploration and evaluation assets.

### Impairment Assessment (2018)

Indicators of impairment were determined to exist in each of Bonavista's CGUs, as a result of a sustained decline in forward commodity benchmark prices for natural gas. As such impairment tests were carried out on each of Bonavista's CGUs, the British Columbia CGU, the West Central CGU and the Deep Basin CGU. In each impairment test the recoverable amount of the CGU was determined to exceed the carrying value and as such no impairment charge was recorded for the year ended December 31, 2018. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

The recoverable amount of each CGU tested for impairment at December 31, 2018 was determined using the methodology and assumptions noted below.

- British Columbia CGU, located mainly in northeast British Columbia near Fort St. John, composed of primarily natural gas and natural gas liquids reserves. The estimated recoverable amount of the British Columbia CGU as at December 31, 2018 was calculated to be $22.9 million. The recoverable amount was determined using the fair value less costs of disposal methodology which is designated as Level 3 on the fair value hierarchy.

- West Central CGU, located between Calgary and Drayton Valley, Alberta, composed of primarily natural gas and natural gas liquids reserves. The estimated recoverable amount of the West Central CGU as at December 31, 2018 was calculated to be $1,413.9 million. The recoverable amount was determined using the value in use methodology.
- Deep Basin CGU, located between Edmonton and Fox Creek, Alberta, composed of primarily natural gas reserves. The estimated recoverable amount of the Deep Basin CGU as at December 31, 2018 was calculated to be $960.5 million. The recoverable amount was determined using the value in use methodology.

The proved plus probable reserve values were based on Bonavista's December 31, 2018 reserve report as prepared by its independent reserve engineer GLJ Petroleum Consultants Ltd. The recoverable amount of the CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates applied to the different reserve categories ranged from eight to 15 percent when the value in use methodology was used and ten to 20 percent when the fair value less costs of disposal methodology was used. Key input estimates used in the determination of cash flows from Bonavista's oil and gas reserves included: quantities of reserves and future production; forward commodity pricing as prepared by the average of four independent reserve engineer evaluators; development costs; operating costs; royalty obligations; abandonment costs; and discount rates.

### Forward Commodity Prices used in the December 31, 2018 Impairment Test(1)

| Year | Edmonton Light Crude Oil | WTI Oil | AECO Gas | Foreign Exchange Rate |
|---|---|---|---|---|
| | (CDN$/bbl) | (US$/bbl) | (CDN$/MMBtu) | (US$/CDN$) |
| 2019 | 66.93 | 58.44 | 1.85 | 0.7575 |
| 2020 | 74.99 | 63.75 | 2.28 | 0.7763 |
| 2021 | 79.71 | 67.28 | 2.68 | 0.7900 |
| 2022 | 82.91 | 70.50 | 2.99 | 0.8000 |
| 2023 | 86.33 | 73.55 | 3.21 | 0.8050 |
| 2024 | 88.28 | 75.27 | 3.37 | 0.8063 |
| 2025 | 90.35 | 77.03 | 3.51 | 0.8063 |
| 2026 | 92.60 | 78.90 | 3.59 | 0.8063 |
| 2027 | 94.48 | 80.49 | 3.68 | 0.8063 |
| 2028 | 96.41 | 82.11 | 3.77 | 0.8063 |
| Thereafter | 2.0%/year | 2.0%/year | 2.0%/year | 0.8063 |

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2019.

The results of Bonavista's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in impairment charges or in the recovery of previously recorded impairment charges.

### Impairment Assessment (2017)

At December 31, 2017, indicators of impairment were determined to exist in two of Bonavista's CGUs, Central Alberta CGU and British Columbia CGU, as a result of the combination of a sustained decline in forward commodity benchmark prices for natural gas, a reduction in future development plans and negative technical reserve revisions. As such impairment tests were carried out on both the Central Alberta CGU and British Columbia CGU resulting in a total impairment charge of $215.0 million.

The proved plus probable reserve values were based on Bonavista's December 31, 2017 reserve report as prepared by its independent reserve engineer GLJ Petroleum Consultants Ltd. The estimated recoverable amount of the British Columbia CGU was determined to be $22.3 million as at December 31, 2017 using the fair value less costs of disposal methodology. The estimated recoverable amount of the Central Alberta CGU was determined to be $1,047.9 million as at December 31, 2017 using the value in use methodology. The recoverable amount of the CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates used ranged from eight to 15 percent.

### Forward Commodity Prices used in the December 31, 2017 Impairment Test[1]

| Year | Edmonton Light Crude Oil | WTI Oil | AECO Gas | Foreign Exchange Rate |
|---|---|---|---|---|
| | (CDN$/bbl) | (US$/bbl) | (CDN$/MMBtu) | (US$/CDN$) |
| 2018 | 67.80 | 56.88 | 2.33 | 0.7875 |
| 2019 | 71.08 | 60.34 | 2.65 | 0.8000 |
| 2020 | 73.53 | 63.70 | 3.08 | 0.8187 |
| 2021 | 77.98 | 68.50 | 3.35 | 0.8337 |
| 2022 | 81.64 | 72.33 | 3.56 | 0.8425 |
| 2023 | 83.56 | 74.19 | 3.67 | 0.8450 |
| 2024 | 85.74 | 76.08 | 3.83 | 0.8450 |
| 2025 | 87.94 | 77.98 | 3.97 | 0.8450 |
| 2026 | 90.00 | 79.76 | 4.06 | 0.8450 |
| 2027 | 91.82 | 81.36 | 4.16 | 0.8450 |
| Thereafter | 2.0%/year | 2.0%/year | 2.0%/year | 0.8450 |

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2018.

## 12. Exploration and evaluation ("E&E") assets

| Carrying amount | |
|---|---|
| ($ thousands) | |
| Balance as at December 31, 2016 | 144,569 |
| Additions | 11,620 |
| Acquisitions | 7,479 |
| Dispositions | (1,168) |
| Transfers to property, plant and equipment | (24,269) |
| Balance as at December 31, 2017 | 138,231 |
| Additions | **8,746** |
| Acquisitions | **11,210** |
| Dispositions | **(106)** |
| Transfers to property, plant and equipment | **(32,064)** |
| Balance as at December 31, 2018 | **126,017** |

Bonavista's E&E assets consist of exploration and development projects which are pending the determination of proved or probable reserves and production. Additions in 2018 and 2017 represent Bonavista's share of costs incurred on E&E assets during the year.

### Impairment Assessment (2018)

At December 31, 2018, Bonavista determined that indicators of impairment existed with respect to its E&E assets largely as a result of changes in future development plans as a result of the decline in forward commodity benchmark prices and as such an impairment test was performed. It was determined that the recoverable amount of Bonavista's E&E assets exceeded the carrying value and, as such, no impairment was recorded for the year ended December 31, 2018.

Further, there was no impairment recorded as a result of the mandatory impairment assessment on the transfer of exploration and evaluation assets to property, plant and equipment during the year ended December 31, 2018.

### Impairment Assessment (2017)

At December 31, 2017, it was determined that indicators of impairment existed with respect to its E&E assets largely as a result of a reduction in future development plans in certain areas and as such an impairment test was performed. It was determined that the recoverable amount of Bonavista's E&E assets exceeded the carrying value and, as such, no impairment was recorded for the year ended December 31, 2017.

Further, there was no impairment recorded as a result of the mandatory impairment assessment on the transfer of exploration and evaluation assets to property, plant and equipment during the year ended December 31, 2017.

## 13. Shareholders' equity

Bonavista is authorized to issue an unlimited number of common shares without nominal or par value, an unlimited number of exchangeable shares without nominal or par value and 10,000,000 preferred shares, issuable in series.

The holders of common shares are entitled to receive dividends as declared by Bonavista and are entitled to one vote per share. Dividends declared for the year ended December 31, 2018 were $0.04 per share (December 31, 2017 - $0.04 per share). Bonavista announces its dividend policy and confirms its dividend payment on a quarterly basis.

On December 14, 2018, Bonavista's Board of Directors declared a quarterly dividend of $0.01 per share, payable in cash to shareholders of record on December 31, 2018. The dividend payment date was January 16, 2019.

The exchangeable shares of Bonavista are exchangeable into common shares based on the exchange ratio, which is adjusted quarterly, to reflect dividends paid on common shares. As a result, cash dividends are not paid on exchangeable shares. The holders of exchangeable shares are entitled to one vote multiplied by the exchange ratio for each exchangeable share.

### a. Issued and outstanding

#### Common shares

| | **Common Shares** | **Amount** |
|---|---|---|
| | (thousands) | ($ thousands) |
| Balance as at December 31, 2016 | 249,277 | 2,837,945 |
| Issued on conversion of exchangeable shares | 30 | 593 |
| Conversion of restricted incentive and performance incentive awards | 2,440 | 111 |
| Share-based compensation | — | 13,994 |
| Balance as at December 31, 2017 | 251,747 | 2,852,643 |
| Issued on conversion of exchangeable shares | **196** | **3,849** |
| Conversion of restricted incentive and performance incentive awards | **3,510** | **—** |
| Share-based compensation | **—** | **14,439** |
| Balance as at December 31, 2018 | **255,453** | **2,870,931** |

#### Exchangeable shares

| | **Year ended December 31, 2018** | | Year ended December 31, 2017 | |
|---|---|---|---|---|
| | **Exchangeable Shares** | **Amount** | Exchangeable Shares | Amount |
| | (thousands) | ($ thousands) | (thousands) | ($ thousands) |
| Balance, beginning of year | 3,238 | 93,266 | 3,259 | 93,859 |
| Exchanged for common shares | **(133)** | **(3,849)** | (21) | (593) |
| Balance, end of year | **3,105** | **89,417** | 3,238 | 93,266 |
| Exchange ratio, end of year | 1.48526 | — | 1.44650 | — |
| Common shares issuable on exchange | **4,611** | **89,417** | 4,684 | 93,266 |

The holders of Bonavista's exchangeable shares are entitled to the number of votes equal to the number of exchangeable shares held multiplied by the exchange ratio in effect. In accordance with the provisions of the Corporation’s exchangeable shares, Bonavista may require, at any time, the exchange of outstanding exchangeable shares as determined by the Board of Directors on the basis of the exchange ratio in effect on the date set by Bonavista (the “Compulsory Exchange Date”). On and after the applicable Compulsory Exchange Date, the holders of Bonavista's exchangeable shares called for exchange shall cease to be holders of such Corporation’s exchangeable shares and shall not be entitled to exercise any of the rights of holders in respect thereof, other than; (i) the right to receive their proportionate part of the common shares; and (ii) the right to receive any declared and unpaid dividends on such common shares.

### b. Share-based compensation

Bonavista has stock option, restricted incentive award and performance incentive award plans, collectively the “long-term incentive plans” that entitle officers, directors, employees and certain consultants to receive shares of the Corporation. The restricted incentive award plan (the "RIA plan") and performance incentive award plan (the "PIA plan") are the only active long-term incentive plans under which Bonavista has shareholder approval to grant new awards. The number of common shares available for issue under the RIA plan and the PIA plan is limited to 5% of Bonavista's issued and outstanding common shares including common shares issuable on the exchange of outstanding exchangeable shares, as approved by shareholders. As at December 31, 2018, the number of shares issuable under Bonavista's long-term incentive plans, in aggregate represented 2.73% of the issued and outstanding common shares including common shares issuable on the conversion of outstanding exchangeable shares.

Share-based compensation expense recognized during the year ended December 31, 2018 was $10.4 million (December 31, 2017 - $15.7 million). For the year ended December 31, 2018, $0.7 million of share-based compensation expense was capitalized to property, plant and equipment (December 31, 2017 - $1.4 million). As at December 31, 2018, the balance of contributed surplus attributable to share-based compensation awards was $53.2 million (December 31, 2017 - $56.5 million).

### Stock Option Plan

At December 31, 2018, there were 34,000 stock option awards outstanding (December 31, 2017 - 65,400) with a weighted average exercise price of $15.71 per share (December 31, 2017 - $16.75 per share). Bonavista has discontinued the stock option plan, however the stock option plan will continue until all stock options granted under the plan have been exercised or have expired. All stock options awards outstanding will expire by December 31, 2019.

### Restricted incentive award plan

Bonavista's RIA plan provides compensation to directors, officers, employees and certain consultants based on the notional number of underlying common shares.

Vesting arrangements are within the discretion of the Board of Directors, but unless otherwise determined by the Board of Directors, all awards granted under the RIA plan vest evenly in three tranches, over a period of three years from the date of grant. On the vesting date, the holder will receive, cash or equivalent common shares for each restricted incentive award, including dividends made on the common shares from the date of the grant up to and including the vesting date, net of the statutory withholding tax.

The fair value of restricted incentive awards is determined at the date of grant by using the closing price(2) of Bonavista's common shares. The amount of share-based compensation expense is reduced by an estimated forfeiture rate, which has been estimated to range from one to 12 percent for outstanding restricted incentive awards. The estimated weighted average fair value of restricted incentive awards granted during the year ended December 31, 2018 was $1.96 per award (December 31, 2017 - $4.80 per award). The fair value is recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon the conversion of the restricted incentive awards, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

The following table summarizes the awards outstanding under the RIA plan at December 31:

| | **Restricted Incentive Awards** |
|---|---|
| Balance as at December 31, 2016 | 2,943,177 |
| Granted | 2,871,761 |
| Reinvestment(1) | 47,673 |
| Vested | (2,438,370) |
| Forfeited | (219,031) |
| Balance as at December 31, 2017 | 3,205,210 |
| Granted | **2,664,639** |
| Reinvestment(1) | **112,279** |
| Vested | **(2,650,006)** |
| Forfeited | **(352,555)** |
| Balance as at December 31, 2018 | **2,979,567** |

(1) Reinvestment of dividends earned during the period outstanding.
(2) Weighted average trading price of twenty days preceding the grant date and expected dividends.

### Performance incentive award plan

Bonavista's PIA plan provides compensation to directors, officers, certain employees and eligible consultants based on the notional number of underlying common shares.

Awards granted under the PIA plan vest thirty-nine months from the initial date of grant and the number of common shares issued for each award is subject to a performance multiplier ranging from 0 to 2. The payout multiplier is dependent on the performance of Bonavista at the end of the vesting period relative to corporate performance measures determined at the discretion of the Board of Directors. The number of common shares issued for each performance incentive award granted is also adjusted for the payment of dividends from the date of grant to the payment date. On the payment date, Bonavista has sole and absolute discretion to settle the performance incentive awards in the form of either cash or common shares, or some combination thereof, however, it is Bonavista's intention to settle the performance incentive awards in the form of common shares.

The fair value of performance incentive awards is determined at the date of grant by using the closing price(2) of Bonavista's common shares, multiplied by the estimated performance multiplier. For the purposes of share-based compensation a performance multiplier of between 1.00 and 1.10 has been assumed for awards granted. Fluctuations in share-based compensation expense may occur due to changes in estimates of performance outcomes. The amount of share-based compensation expense is reduced by an estimated forfeiture rate, which has been estimated to range from two to 18 percent for outstanding performance incentive awards. The estimated weighted average fair value of PIAs granted during the year ended December 31, 2018 was $1.96 per award (December 31, 2017 - $4.88 per award). Awards granted under the PIA plan vest thirty-nine months from the initial date of grant.

The following table summarizes the awards outstanding under the performance incentive award plan at December 31:

| | **Performance Incentive Awards** |
|---|---|
| Balance as at December 31, 2016 | 1,881,519 |
| Granted | 1,578,666 |
| Reinvestment(1) | 37,583 |
| Vested | (1,336) |
| Forfeited | (97,460) |
| Balance as at December 31, 2017 | 3,398,972 |
| Granted | **1,747,150** |
| Reinvestment(1) | **160,993** |
| Vested | **(859,676)** |
| Forfeited | **(324,734)** |
| Balance as at December 31, 2018 | **4,122,705** |

(1) Reinvestment of dividends earned during the period outstanding and awards earned from the performance multiplier on vesting.
(2) Weighted average trading price of the twenty days preceding the grant date and expected dividends.

### c. Per share amounts

The following table summarizes the weighted average common shares and exchangeable shares used in calculating net income (loss) per equivalent share:

| | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| (thousands) | | |
| Common shares | **254,087** | 250,850 |
| Exchangeable shares converted at the exchange ratio | **4,694** | 4,709 |
| Basic equivalent shares | **258,781** | 255,559 |
| Restricted incentive awards | **2,881** | 3,116 |
| Performance incentive awards | **4,009** | 3,371 |
| Diluted equivalent shares | **265,671** | 262,046 |

## 14. Long-term debt

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Bank credit facility(1) | **11,968** | 71,549 |
| Senior unsecured notes(1)(2) | **789,657** | 728,995 |
| Total long-term debt | **801,625** | 800,544 |

(1) Includes debt issue costs calculated using the effective interest rate method, of which $1.0 million (December 31, 2017 - $1.4 million) pertains to the bank credit facility and $1.1 million (December 31, 2017 - $1.4 million) pertains to senior unsecured notes.
(2) Senior unsecured notes consist of CDN$20.0 million and US$565.0 million valued using the exchange rate at December 31, 2018 of $1.3641 CDN to $1.0000 US dollar (December 31, 2017 - $1.2573 CDN to $1.0000 US dollar).

### a. Bank credit facility

Bonavista has a bank credit facility of $500 million, provided by a syndicate of eight domestic banks. There is an accordion feature providing that at any time during the term, on participation of any existing or additional lenders, Bonavista can increase the bank credit facility by $100 million. The bank credit facility is a four year revolving credit facility and may, at the request of Bonavista with the consent of the lenders, be extended on an annual basis beyond the existing term. The current maturity date of the bank credit facility is September 10, 2021. Bonavista also has in place a $50 million demand working capital facility, which is subject to the same covenants as the bank credit facility.

The bank credit facility provides that advances may be made by way of Canadian prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The total stamping fees range between 50 basis points and 215 basis points on Canadian bank prime and US base rate borrowings and between 150 basis points and 315 basis points on Canadian dollar bankers' acceptance and US dollar LIBOR borrowings. The undrawn portion of the bank credit facility is subject to a standby fee in the range of 30 to 63 basis points. For the year ended December 31, 2018, borrowing costs averaged 4.0% (December 31, 2017 - 3.6%).

At December 31, 2018, Bonavista had $13.0 million drawn (December 31, 2017 - $72.9 million) on its bank credit facility and outstanding letters of credit of $17.3 million (December 31, 2017 - $18.0 million), which reduce the available borrowing capacity on its bank credit facility. For the years ended December 31, 2018 and December 31, 2017, Bonavista had no amounts drawn on its demand working capital facility.

### b. Senior unsecured notes issued under a master shelf agreement

Bonavista entered into an uncommitted master shelf agreement that allows for an aggregate draw of up to US$125 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. In 2010, Bonavista drew down US$50 million on the master shelf agreement with a coupon rate of 4.86%. Of the US$50 million drawn, US$25 million was repaid on June 4, 2016 and the remaining US$25 million was repaid on June 4, 2017.

Bonavista increased its existing master shelf agreement from US$125 million to US$150 million allowing the Corporation to draw an additional US$100 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On April 25, 2013, the Corporation drew down US $100 million on the master shelf agreement with a coupon rate of 3.80% and a maturity date of April 25, 2025.

### c. Senior unsecured notes not subject to the master shelf agreement

Bonavista issued the following senior unsecured notes by way of a private placement.

Bonavista's senior unsecured notes, including those senior unsecured notes issued under the master shelf agreement, bear fixed interest rates, with a weighted average rate of 4.1% for the years ended December 31, 2018 and 2017. The senior unsecured notes outstanding have maturity dates ranging from November 2, 2020 to May 23, 2025. On November 2, 2017, Bonavista repaid US$90 million with a coupon rate of 3.66%.

The terms and coupon rates of the senior unsecured notes, not subject to the master shelf agreement, are summarized below:

| Issued Date | Principal | | Coupon Rate | Maturity Dates |
|---|---|---|---|---|
| November 2, 2010 | US | $160.0 million | 4.37% | November 2, 2020 |
| November 2, 2010 | US | $50.0 million | 4.47% | November 2, 2022 |
| October 25, 2011 | US | $150.0 million | 4.25% | October 25, 2021 |
| May 23, 2013 | US | $85.0 million | 3.68% | May 23, 2023 |
| May 23, 2013 | CDN | $20.0 million | 4.09% | May 23, 2023 |
| May 23, 2013 | US | $20.0 million | 3.78% | May 23, 2025 |

### d. Debt Covenants

Under the terms of the bank credit facility, Bonavista has provided the covenants that its:

- consolidated senior debt borrowing will not exceed three and one half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment;
- consolidated total debt will not exceed three and one half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and
- consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholders' equity of the Corporation, in all cases calculated based on a rolling prior four quarters.

Bonavista's consolidated senior debt and consolidated total debt were the same at December 31, 2018 and include Bonavista's senior unsecured notes issued under the master shelf agreement, senior unsecured notes not subject to the master shelf agreement and the bank credit facility. Bonavista's consolidated senior debt may differ from total debt in instances when the Corporation issues senior subordinated debt or enters into a significant capital lease obligation or guarantee.

Under the terms of the master shelf agreement and senior unsecured notes, Bonavista has provided similar significant covenants that exist under the bank credit facility.

At December 31, 2018, Bonavista was in compliance with all covenants under its credit facilities and senior unsecured notes. Total long-term debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and total senior debt to EBITDA was 2.8 times compared to the covenant of less than 3.5 times and total long-term debt to capitalization was 0.35 times compared to the covenant of less than 0.5 times.

## 15. Decommissioning liabilities

Bonavista's decommissioning liabilities results from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. Bonavista estimates the net present value of its total decommissioning liabilities to be $430.7 million at December 31, 2018 (December 31, 2017 - $409.3 million), based on an estimated total future undiscounted liability of approximately $874.6 million (December 31, 2017 - $837.3 million). At December 31, 2018 management estimates expenditures required to settle the liability will be made over the next 55 years with the majority of payments being made in years 2051 to 2071. A risk-free rate of approximately 2.2% (December 31, 2017 - 2.3%) based on the Bank of Canada's long-term risk-free bond rate and an inflation rate of 1.8% (December 31, 2017 - 1.8%) were used to calculate the present value of the decommissioning liability as at December 31, 2018.

The following table reconciles Bonavista's provision for its decommissioning liabilities:

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Balance, beginning of year | 409,326 | 437,922 |
| Accretion expense | **8,891** | 8,581 |
| Liabilities incurred | **2,219** | 5,642 |
| Liabilities acquired | **4,825** | 1,034 |
| Liabilities disposed | **(1,999)** | (14,242) |
| Liabilities settled | **(12,318)** | (17,318) |
| Change in estimate[1] | **19,802** | (12,293) |
| Balance, end of year | **430,746** | 409,326 |
| Expected to be incurred within one year | **11,704** | 16,146 |
| Expected to be incurred beyond one year | **419,042** | 393,180 |

(1) Relates to changes in estimated costs, discount rates and anticipated settlement dates of decommissioning liabilities.

## 16. Deferred income taxes

The provision for income tax differs from the result which would have been obtained by applying the combined Federal and Provincial income tax rates to net income before taxes. The difference results from the following items:

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Income (loss) before taxes | **26,914** | (44,181) |
| Current statutory income tax rate[1] | **27%** | 27% |
| Income tax expense (recovery) at current statutory rate | **7,267** | (11,929) |
| Non-deductible (taxable) portion of realized and unrealized foreign exchange | **2,808** | (3,694) |
| Change in unrecognized deferred tax liability (asset) | **2,808** | (3,694) |
| Non-deductible share-based compensation | **2,390** | 2,760 |
| Other | **(174)** | 306 |
| Deferred income taxes | **15,099** | (16,251) |

(1) The tax rate consists of the combined federal and provincial statutory tax rates for Bonavista for the years ended December 31, 2018 and December 31, 2017.

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Deferred income tax liabilities: | | |
| Capital assets in excess of tax value | **345,354** | 318,160 |
| Financial instrument contracts | **18,662** | 7,063 |
| Debt issue costs | **543** | 730 |
| Deferred income tax assets: | | |
| Decommissioning liabilities | **(116,172)** | (110,395) |
| Non-capital losses | **(220,620)** | (201,841) |
| Other liability | **(2,986)** | (2,378) |
| Share-based compensation | **(1,099)** | (1,937) |
| Issue costs | **(671)** | (1,490) |
| Deferred income tax liability | **23,011** | 7,912 |

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

| ($ thousands) | Balance December 31, 2016 (Asset)/Liability | Recognized in profit and loss (Recovery)/Expense | Recognized in equity (Asset)/Liability | Balance December 31, 2017 (Asset)/Liability |
|---|---|---|---|---|
| Property, plant and equipment | 346,796 | (28,636) | — | 318,160 |
| Decommissioning liabilities | (118,108) | 7,713 | — | (110,395) |
| Non-capital losses | (175,784) | (26,057) | — | (201,841) |
| Issue costs | (2,165) | 675 | — | (1,490) |
| Other liability | (2,897) | 519 | — | (2,378) |
| Debt issue costs | 745 | (15) | — | 730 |
| Financial instrument contracts | (21,961) | 29,024 | — | 7,063 |
| Share-based compensation | (2,352) | 526 | (111) | (1,937) |
| | 24,274 | (16,251) | (111) | 7,912 |

| | Balance December 31, 2017 (Asset)/Liability | **Recognized in profit and loss (Recovery)/Expense** | **Recognized in equity (Asset)/Liability** | **Balance December 31, 2018 (Asset)/Liability** |
|---|---|---|---|---|
| ($ thousands) | | | | |
| Property, plant and equipment | 318,160 | **27,194** | **—** | **345,354** |
| Decommissioning liabilities | (110,395) | **(5,777)** | **—** | **(116,172)** |
| Non-capital losses | (201,841) | **(18,779)** | **—** | **(220,620)** |
| Issue costs | (1,490) | **819** | **—** | **(671)** |
| Other liability | (2,378) | **(608)** | **—** | **(2,986)** |
| Debt issue costs | 730 | **(187)** | **—** | **543** |
| Financial instrument contracts | 7,063 | **11,599** | **—** | **18,662** |
| Share-based compensation | (1,937) | **838** | **—** | **(1,099)** |
| | 7,912 | **15,099** | **—** | **23,011** |

The following is a summary of Bonavista's estimated tax pools:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| ($ thousands) | | |
| Canadian oil and gas property expense | **435,744** | 482,916 |
| Canadian development expense | **447,826** | 544,348 |
| Canadian exploration expense | **369,612** | 340,252 |
| Undepreciated capital cost | **218,970** | 242,015 |
| Non-capital losses | **818,029** | 748,026 |
| Other | **6,954** | 5,523 |
| Total | **2,297,135** | 2,363,080 |

Non-capital losses carry forward of $818.0 million (December 31, 2017 - $748.0 million) expire in the years 2028 through 2038. Bonavista has capital losses of $36.1 million (December 31, 2017 - $38.0 million) available for carry forward against future capital gains indefinitely that are not included in the deferred income tax liability. For the years ended December 31, 2018 and 2017 Bonavista paid no tax installments.

## 17. Contractual obligations and commitments

The following table is a summary of Bonavista's contractual obligations and commitments at December 31, 2018:

| | Total | 2019 | 2020 | 2021 | 2022 | 2023 and thereafter |
|---|---|---|---|---|---|---|
| ($ thousands) | | | | | | |
| Long-term debt repayments(1)(3)(4) | 801,625 | — | 218,033 | 216,268 | 68,084 | 299,240 |
| Interest payments(2)(3) | 115,159 | 32,582 | 31,019 | 21,475 | 13,683 | 16,400 |
| Office lease(5) | 10,703 | 6,760 | 3,943 | — | — | — |
| Transportation expenses(6) | 147,106 | 31,682 | 29,732 | 27,651 | 25,830 | 32,211 |
| Total contractual obligations | **1,074,593** | **71,024** | **282,727** | **265,394** | **107,597** | **347,851** |

(1) Long-term debt repayments include the principal payments due on senior unsecured notes. Based on the existing terms of the revolving bank credit facility, the amounts owing under this facility are required to be paid on September 10, 2021.
(2) Fixed interest payments on senior unsecured notes.
(3) US dollar payments are converted using the exchange rate at December 31, 2018 of $1.3641 CDN to $1.0000 US dollar.
(4) With respect to the long-term debt repayment obligations Bonavista has entered into financial instrument contracts to reduce its exposure to the CDN dollar to the US dollar exchange rate associated with the future cash repayments of its US denominated senior unsecured notes. The underlying notional amount of the financial instrument contracts maturing on the maturity dates of Bonavista US denominated senior unsecured notes is US$400 million at an average CDN$/US$ rate of $1.3015.
(5) Office lease expires July 31, 2020.
(6) Includes a Long Term Fixed Price (LTFP) contract with TransCanada that commenced November 1, 2017. This 10-year contract contains an early termination policy after 5 years which has been assumed to be exercised in the contractual obligation above.

## 18. Supplemental disclosure

### a. Income statement presentation

Bonavista's statement of income (loss) and comprehensive income (loss) is prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in the operating and general and administrative expenses in the statement of income (loss) and comprehensive income (loss):

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Operating | **8,198** | 8,794 |
| General and administrative | **21,792** | 23,462 |
| Total employee compensation costs | **29,990** | 32,256 |

For the year ended December 31, 2018, $3.0 million (December 31, 2017 - $2.7 million) of employee compensation costs were capitalized.

### b. Compensation of key management personnel

Bonavista has determined that its key management personnel includes both officers and directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. In addition, share-based compensation provided to key management personnel includes awards offered under Bonavista's long-term incentive plans.

The following table details remuneration to key management personnel included in general and administrative expenses in the statement of income (loss) and comprehensive income (loss).

| ($ thousands) | **Year ended December 31, 2018** | Year ended December 31, 2017 |
|---|---|---|
| Short-term benefits | **3,356** | 3,437 |
| Share-based payments(1) | **3,068** | 7,661 |
| | **6,424** | 11,098 |

(1) Share-based payments represent the fair value of restricted incentive and performance incentive awards granted during the period.

### c. Reconciliation of financing liabilities arising from financing activities

The following table provides a detailed breakdown of the cash and non-cash changes in financing liabilities arising from financing activities:

| ($ thousands) | Year ended December 31, 2017 | **Cash flows** | **Amortization of debt issue costs** | **Unrealized foreign exchange loss** | **Year ended December 31, 2018** |
|---|---|---|---|---|---|
| Bank credit facility | 71,549 | **(60,015)** | **434** | — | **11,968** |
| Senior unsecured notes | 728,995 | **—** | **320** | **60,342** | **789,657** |
| Total financial liabilities from financing activities | 800,544 | **(60,015)** | **754** | **60,342** | **801,625** |

# CORPORATE INFORMATION

## DIRECTORS

***Keith A. MacPhail,*** *(2)(3)(5)*
*Chair*

***Jason E. Skehar,*** *(5)*
*President and Chief Executive Officer*

***Ian S. Brown*** *(1)(4)*

***David P. Carey*** *(2)(4)*

***Theresa B.Y. Jang*** *(1)(3)*

***Michael M. Kanovsky*** *(1)(2)(4)(5)*

***Robert G. Phillips*** *(3)(4)*

***Ronald J. Poelzer*** *(1)(5)*

***Christopher P. Slubicki*** *(2)(3)(5)*

*(1) Member of the Audit Committee*

*(2) Member of the Reserves Committee*

*(3) Member of the Compensation Committee*

*(4) Member of the Governance and Nominating Committee*

*(5) Member of the Executive Committee*

## OFFICERS

***Jason E. Skehar,***
*President and Chief Executive Officer*

***Bruce W. Jensen,***
*Chief Operating Officer*

***Dean M. Kobelka,***
*Vice President, Finance and Chief Financial Officer*

***Rochelle L. Estep,***
*Vice President, Strategy and Planning*

***Colin J. Ranger,***
*Vice President, Operations*

***Lynda J. Robinson,***
*Vice President, Human Resources and Administration*

***Scott W. Shimek,***
*Vice President, Resource Development*

***Grant A. Zawalsky,***
*Corporate Secretary*

## AUDITORS

*KPMG LLP*
*Chartered Professional Accountants*
*Calgary, Alberta*

## BANKERS

*Canadian Imperial Bank of Commerce*
*The Toronto-Dominion Bank*
*Bank of Montreal*
*Royal Bank of Canada*
*The Bank of Nova Scotia*
*National Bank of Canada*
*Alberta Treasury Branches*
*Caisse Centrale Desjardins*
*Calgary, Alberta*

## ENGINEERING CONSULTANTS

*GLJ Petroleum Consultants Ltd.*
*Calgary, Alberta*

## LEGAL COUNSEL

*Burnet, Duckworth & Palmer LLP*
*Calgary, Alberta*

## REGISTRAR AND TRANSFER AGENT

*Computershare Trust Company of Canada*
*Calgary, Alberta*

## STOCK EXCHANGE LISTING

*Toronto Stock Exchange*
*Trading Symbol "BNP"*

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*Jason E. Skehar*
*President and CEO*

*or*

*Dean M. Kobelka*
*Vice President, Finance and CFO*

BONAVISTA
ENERGY CORPORATION