BONAVISTA ENERGY CORPORATION

ANNUAL REPORT 2017

March 1, 2018

Highlights

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
Financial						
($ thousands, except per share)						
Production revenues	**147,188**	141,842	4 %	**553,002**	445,434	24 %
Adjusted funds flow(1)	**86,108**	78,742	9 %	**301,988**	264,391	14 %
Per share(1) (2)	**0.33**	0.31	6 %	**1.18**	1.11	6 %
Dividends declared	**2,518**	2,493	1 %	**10,040**	13,891	(28)%
Per share	**0.01**	0.01	— %	**0.04**	0.06	(33)%
Net loss	**(159,149)**	(12,021)	1,224 %	**(27,930)**	(95,998)	(71)%
Per share(3)	**(0.62)**	(0.05)	1,140 %	**(0.11)**	(0.40)	(73)%
Adjusted net income(4)	**4,727**	60,855	(92)%	**50,646**	22,259	128 %
Per share(3)	**0.02**	0.24	(92)%	**0.20**	0.09	122 %
Total assets				**2,959,470**	3,172,157	(7)%
Long-term debt, net of working capital				**829,969**	946,935	(12)%
Long-term debt, net of adjusted working capital(5)				**840,173**	877,523	(4)%
Shareholders' equity				**1,539,461**	1,560,244	(1)%
Capital expenditures:						
Exploration and development	**59,722**	58,574	2 %	**289,029**	153,871	88 %
Dispositions, net of acquisitions	**(2,074)**	(117,666)	(98)%	**(7,841)**	(167,905)	(95)%
Weighted average outstanding equivalent shares: (thousands)(3)						
Basic	**256,386**	253,906	1 %	**255,559**	237,806	7 %
Diluted	**262,980**	258,729	2 %	**262,046**	242,106	8 %
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (mmcf/day)	**318**	278	14 %	**306**	280	9 %
Natural gas liquids (bbls/day)	**19,284**	19,941	(3)%	**18,794**	18,247	3 %
Oil (bbls/day)(6)	**2,463**	3,069	(20)%	**2,415**	3,708	(35)%
Total oil equivalent (boe/day)	**74,799**	69,339	8 %	**72,156**	68,550	5 %
Product prices:(7)						
Natural gas ($/mcf)	**3.14**	3.31	(5)%	**3.05**	3.13	(3)%
Natural gas liquids ($/bbl)	**28.47**	25.83	10 %	**27.29**	19.97	37 %
Oil ($/bbl)(6)	**59.49**	68.80	(14)%	**57.80**	61.89	(7)%
Total oil equivalent ($/boe)	**22.65**	23.75	(5)%	**21.97**	21.41	3 %
Operating expenses ($/boe)	**5.57**	5.75	(3)%	**5.59**	5.60	— %
General and administrative expenses ($/boe)	**0.99**	1.09	(9)%	**0.94**	1.08	(13)%
Cash costs ($/boe)(8)	**8.96**	9.40	(5)%	**8.92**	9.40	(5)%
Operating netback ($/boe)(9)	**14.81**	15.14	(2)%	**13.85**	13.44	3 %

NOTES:

(1) Management uses adjusted funds flow to analyze operating performance, dividend coverage and leverage. Adjusted funds flow as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Adjusted funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with IFRS. All references to adjusted funds flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures and interest expense. Adjusted funds flow per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income (loss) per share.

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

(3) Per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

(4) Amounts have been adjusted to exclude unrealized gains and losses on financial instrument commodity contracts and impairment, net of tax.

(5) Amounts have been adjusted to exclude associated assets or liabilities from financial instrument commodity contracts and decommissioning liabilities. Also referenced as Total net debt.

(6) Oil includes light, medium and heavy oil.

(7) Product prices include realized gains and losses on financial instrument commodity contracts.

(8) Cash costs equal the total of operating, transportation, general and administrative, and financing expenses.

(9) Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, operating and transportation expenses calculated on a per boe basis.

Highlights (cont'd)			
Years ended December 31	**2017**	2016	% Change
Drilling:			
Gross	**61**	46	33 %
Net	**56.7**	43.1	32 %
Land (net acres):			
Undeveloped	**536,556**	568,051	(6)%
Total	**1,681,279**	1,754,634	(4)%
Reserves:(10)			
Proved producing:			
Natural gas (bcf)(11)	**642.4**	632.3	2 %
Oil and natural gas liquids (mbbls)(12)	**47,756**	50,517	(5)%
Total oil equivalent (mboe)	**154,819**	155,907	(1)%
Total proved:			
Natural gas (bcf)(11)	**1,155.0**	1,128.1	2 %
Oil and natural gas liquids (mbbls)(12)	**82,507**	85,159	(3)%
Total oil equivalent (mboe)	**275,008**	273,183	1 %
Proved plus probable:			
Natural gas (bcf)(11)	**1,877.0**	1,721.0	9 %
Oil and natural gas liquids (mbbls)(12)	**124,906**	127,366	(2)%
Total oil equivalent (mboe)	**437,743**	414,205	6 %
% Proved producing	**35%**	38%	(3)%
% Proved	**63%**	66%	(3)%
% Probable	**37%**	34%	3 %
Net present value of future cash flow before income taxes ($ millions, proved plus probable):			
0% discount rate	**5,542**	6,050	(8)%
5% discount rate	**3,520**	3,876	(9)%
10% discount rate	**2,452**	2,748	(11)%
15% discount rate	**1,830**	2,092	(13)%
Reserve life index (years):(13)			
Total proved	**10.3**	10.5	(2)%
Proved plus probable	**15.2**	14.4	6 %
Reserves (boe per thousand shares - basic)(3):			
Total proved	**1,076**	1,149	(6)%
Proved plus probable	**1,713**	1,742	(2)%
Finding and development costs - proved plus probable ($/boe)(14)	**7.60**	6.97	9 %
Recycle ratio - proved plus probable(15)	**1.8**	1.9	(5)%
Finding, development and acquisition costs - proved plus probable ($/boe)(14)	**7.56**	(0.55)	(1,475)%
Recycle ratio - proved plus probable(15)	**1.8**	(24.4)	(107)%

NOTES:
(10) Working interest reserves are gross reserves prior to deduction of royalties and without including any of Bonavista's royalty interests.
(11) Includes Conventional Natural Gas and Coal Bed Methane.
(12) Includes Natural Gas Liquids; and Light, Medium and Heavy Oil.
(13) Calculated based on the amount for the relevant reserve category divided by the production forecast prepared by the independent reserve evaluator (GLJ).
(14) Includes changes in future development costs.
(15) Recycle ratio is calculated using operating netback per boe divided by either finding and development or finding, development and acquisition costs per boe.

Share Trading Statistics	Three months ended December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
($ per share, except volume)				
High	3.01	3.37	3.56	5.22
Low	1.77	2.55	2.22	3.05
Close	2.25	2.98	2.71	3.46
Average Daily Volume - Shares	860,422	617,169	822,516	819,104

MESSAGE TO SHAREHOLDERS

Bonavista strategically invested in our two core areas in 2017 to generate 14% growth in adjusted funds flow, six percent growth in proved plus probable reserves and five percent growth in production. Most notably, these accomplishments were achieved while underspending adjusted funds flow, providing an opportunity to further reduce debt and close the year with net debt to 2017 fourth quarter annualized adjusted funds flow ratio of 2.4:1.

Our Deep Basin core area experienced record levels of investment driving 39% growth in production volumes and 23% growth in net operating income. Meanwhile, our West Central core area production remained stable while re-investing only 66% of net operating income in this core area in 2017.

Notwithstanding the prevailing rise in activity levels and service costs throughout the basin in 2017, we remained disciplined with our spending resulting in improvements throughout our cost structure. Our cash costs improved five percent, we added production eight percent more efficiently and our cost to add reserves remained low improving our three-year trailing finding and development costs by 19%. This efficient cost structure coupled with the flexibility to allocate capital between two core areas, unique in their investment attractiveness, will continue to allow us to adapt to the ever-changing environment.

For Bonavista, the aspiration to continue to grow in 2018 is subdued in light of current commodity prices in western Canada. Hence, our approach to 2018 will focus on creating incremental financial flexibility by allocating 30-40% of adjusted funds flow to the repayment of debt. The remainder of our adjusted funds flow will be allocated to a moderate capital spending program to maintain production while preserving the majority of our inventory during this low commodity price environment. We intend to enhance our revenues by allocating most of this capital program towards natural gas liquids ("NGL") rich development, primarily in our West Central core area. Accordingly, this approach will strengthen Bonavista's position to grow shareholder value in a more constructive commodity price environment.

Operational and financial accomplishments for 2017 include:

- Delivered eight percent growth in fourth quarter production to 74,799 boe per day and five percent growth in annual average production to 72,156 boe per day;
- Improved our adjusted funds flow to $302.0 million, representing growth of 14% over 2016;
- Reduced 2017 cash costs to $8.92 per boe, representing an improvement of five percent when compared to 2016;
- Reduced our costs to add production through our exploration and development ("E&D") program by eight percent to $12,500 per boe per day when compared to 2016;
- Replaced 189% of 2017 production with the addition of 49.8 MMboe of proved plus probable reserves;
- Reduced long-term debt (net of adjusted working capital) by four percent to $840.2 million, resulting in net debt to fourth quarter 2017 annualized adjusted funds flow of 2.4:1;
- Prudently protected 2018 adjusted funds flow with a commodity hedge portfolio resulting in 73% of our forecasted 2018 total revenue hedged and 56% of our forecasted 2018 natural gas production hedged at an AECO price of $3.07 per mcf; and
- Diversified our natural gas delivery points beyond AECO whereby when coupled with our hedge portfolio, we have 14% of our summer 2018 natural gas production forecast exposed to daily AECO volatility.

2017 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

Our Deep Basin core area is characterized by stacked, resource-rich natural gas reservoirs with low cost and high margin operations. Our production base and development plans are supported by having ownership in approximately 266 mmcf per day of operating process capacity, and adequate firm receipt service on NOVA Gas Transmission Ltd. ("NGTL") to accommodate all of our budgeted natural gas production for 2018.

In 2017, we allocated 53% of our E&D capital program to the Deep Basin amounting to $152.4 million on E&D activities to drill 30 (26.5 net) horizontal wells. This level of investment generated average production rates of 26,880 boe per day representing 39% growth over 2016.

In 2018, we forecast E&D spending of $48 million drilling 11 (7.3 net) wells which will maintain our average annual production of approximately 27,000 boe per day.

Spirit River (Wilrich, Falher, Notikewin) Natural Gas

We drilled 23 (21.8 net) horizontal Spirit River wells in 2017 including 19 (18.1 net) extended reach horizontal ("ERH") wells. During the fourth quarter, we drilled six (5.1 net) Spirit River ERH wells, with four of these wells being completed in the first quarter of 2018.

The majority (16.0 net) of the Spirit River wells drilled in 2017 were in the Wilrich formation at Ansell, 14 of which were ERH wells. In the fourth quarter, four (4.0 net) Wilrich wells were drilled at Ansell including two as part of a four well pad completed late in the quarter. These four wells have been on stream at similar rates to the rest of our 2017 ERH Wilrich wells. More importantly, our average cost to drill, complete, equip and tie-in these wells has dropped nine percent relative to the remainder of our 2017 Ansell Wilrich program. Overall, our 2017 ERH wells are performing at average rates of approximately 600 boe per day per well for the first 12 months of production. This represents a 48% increase over the wells drilled during the same period in 2016. Additionally, capital efficiencies have continued to improve to $7,600 per boe per day and represent a 30% reduction compared to our 2016 wells. Performance of our 2017 ERH program was attributed to a better understanding of the reservoir in addition to innovative drilling and completion techniques including orientation, lateral length, fluid design and stage density.

Early in the first quarter of 2018, we completed our first Notikewin ERH well with notable results. For the first month of production the well is producing six mmcf per day under restrictive back pressure as the well is flowing into the high pressure inlet of the gas plant. By the end of the first quarter we plan to complete five additional Spirit River locations.

With subdued natural gas prices expected for the balance of 2018 we are allocating most of our capital towards higher NGL rich development opportunities in our portfolio for the remainder of 2018. As such, we plan to drill only four (3.3 net) Spirit River wells, two (2.0 net) of which are Wilrich wells in 2018.

Other Deep Basin Plays

With the multi-zone nature of the Deep Basin we are allocating 59% of our 2018 Deep Basin capital program to delineating oil or higher NGL plays in the Cardium, Bluesky and Ellerslie formations. In 2017, seven (4.7 net) wells were drilled in these plays, most of which are being completed in the first quarter of 2018. We have been encouraged by the results to date and for 2018, we expect to drill another seven (3.9 net) wells in these same formations.

WEST CENTRAL CORE AREA

Our West Central core area has a predictable production base with approximately 750,000 net acres and a drilling inventory of approximately 720 horizontal locations. This area draws its strength from a modest decline rate of 21%, low cost structure, extensive infrastructure and consistent well results.

In 2017, we spent $130.6 million on E&D activities, which included drilling 31 (30.2 net) horizontal wells, supporting production rates averaging 41,929 boe per day or 58% of corporate production. In 2018, we plan to drill 18 (17.4 net) wells, with E&D spending of $87 million inclusive of incremental infrastructure spending. Our development in 2018 is focused at Morningside and Strachan where we are targeting liquids rich development opportunities. This capital program will maintain production near 40,000 boe per day (while consuming only 60% of net operating income generated in this core area).

Glauconite Natural Gas

We drilled 16 (15.7 net) horizontal wells in 2017 including two (2.0 net) in the fourth quarter resulting in average 2017 production of 22,241 boe per day.

Of the 16 Glauconite wells drilled in 2017, 13 (12.7 net) were in the Hoadley area where we improved our efficiencies by drilling longer length horizontals with less capital. The average lateral length of our 2017 Hoadley drilling program was approximately 2,200 meters at a cost of $710 per meter, over 20% less than our 2016 costs per lateral length. In the fourth quarter we completed three Hoadley Glauconite wells targeting higher field condensate areas. These wells are producing above our expected natural gas rates with field condensate ratio's more than double our average at Hoadley.

During the fourth quarter, we entered into a new firm processing agreement for our Strachan production. This new agreement will take effect June 2018 and result in operating cost reductions of approximately 50% to $3.50 per boe. This efficient, low cost processing solution will also offer significant available processing capacity for future growth.

The combination of reduced processing costs and improving NGL pricing and recoveries will result in Strachan portraying some of the most economic development for Bonavista in 2018. With approximately 50 barrels per mmcf of natural gas liquids weighted 55% to condensate, we will allocate approximately 30% of our value capital program to Strachan.

The predictable and reliable nature of our Glauconite play, coupled with its resilient economics and NGL development opportunities will continue to generate dependable adjusted funds flow in 2018. Overall we anticipate a capital program of $31 million to drill eight (7.5 net) Glauconite wells in 2018.

Spirit River Falher Natural Gas

We drilled thirteen (13.0 net) horizontal wells in 2017 at Morningside, seven (7.0 net) of which were ERH wells. Our ERH development in this area has resulted in a step change in economic performance for Bonavista this year. With each ERH well, our intent is to access twice as much reservoir in less than 48 hours of incremental drilling time resulting in material improvements in capital efficiency. Accordingly, our 2017 ERH wells have delivered capital efficiencies of $6,400 per boe per day, amongst the best in Western Canada. Currently, ERH wells represent 60% of our total drilling inventory at Morningside.

The prolific production rates from our ERH wells at Morningside resulted in average fourth quarter production of 6,100 boe per day, representing 196% growth from the prior year period. We supported this growth in 2017 by investing $9 million in facilities and infrastructure throughout the year.

In the first quarter of 2018, we have successfully drilled and tested a Falher step-out well that significantly extends the play. The well had a final test rate of five mmcf per day and will be on production by the end of February. With well costs of $3.3 million and NGL yields of 100 bbls per mmcf the Morningside Falher play generates competitive economics in this low AECO price environment. As such, we plan to drill nine (8.9 net) wells in 2018 representing 24% of our value capital program.

STRENGTHS OF BONAVISTA ENERGY CORPORATION

Throughout our 21 year history, from an initial restructuring in 1997 to create a high growth junior exploration company, through the energy trust phase between July 2003 and December 2010, to a dividend paying corporation, Bonavista has remained committed to the same operating philosophies despite the endless commodity price volatility and uncertainty inherent in the energy sector. We have consistently maintained a high level of profitable investment activity on our asset base. This activity stems from the expertise of our people and their entrepreneurial approach to design profitable development projects with resilience to an unpredictable commodity price environment. Our experienced technical teams have a thorough understanding of our assets and the reservoirs within the Western Canadian Sedimentary Basin as they exercise the discipline and commitment required to deliver long-term value to our shareholders. The core operating and financial principles that guide our people have been with our organization from the beginning and remain solidly intact today.

Our production and development activity is largely concentrated in two core areas in Alberta which together represented approximately 99% of 2017 net operating income. We create opportunities through undeveloped land purchases, asset swaps, asset acquisitions and farm-in opportunities in these areas. Specifically over the past five years, advanced technology coupled with North American natural gas supply/demand fundamentals has led to numerous opportunities to reposition the asset portfolio and drastically improve the quality and economics of our development projects. These activities have led to low cost reserve additions and a reliable production base. Today, the predictable production performance and optimized cost structure of our asset base ensures operating netbacks that compete favorably in most operating environments. Furthermore, our assets are predominantly operated, providing control over the pace of operations and a direct influence over our operating and capital cost efficiencies.

Our team brings a successful track record of executing reliable development programs with consistency and precision. We continually strive for balance sheet flexibility and remain focused on prudent financial management. Our Board of Directors and management team possess extensive experience in the oil and natural gas business. They have successfully guided our organization through many different economic cycles utilizing a proven strategy underpinned with a set of consistent and reliable operating and financial principles. Directors, management and employees also own approximately nine percent of the equity of Bonavista, aligning our interests with those of external shareholders.

OUTLOOK

Despite the resilience to volatile commodity prices demonstrated in the past five years, our sector has experienced incremental headwinds in the past 12 months creating a challenging reinvestment environment. Simply put, our pipelines are full. As an industry and a nation, we continue to experience barriers with efficiently and effectively expanding the infrastructure required to transport our nation's growing supply of world class natural resources to markets both domestically and internationally. As a result, our products are being heavily discounted in price creating an opportunity for our competitors (some of which are customers at these prices) to gain market share in supplying the world with the energy they demand.

Although short-term natural gas fundamentals appear to be challenged, we believe the longer-term is setting up constructively for natural gas prices. Much of the imbalance we have recently experienced in North America is due to the tremendous supply growth in the U.S. Fortunately, year-over-year growth rates have slowed in the Appalachian and Permian as new-well natural gas production per rig has flattened in 2017. As productivity enhancements wane, higher North American prices will likely be required to replace declines.

In addition, Liquefied natural gas ("LNG") export capacity has been endorsed and promoted by citizens and policy makers in the U.S. and is expected to triple to approximately 10 billion cubic feet per day by the end of 2019. Alongside, China's share of global LNG consumption continues to grow rapidly as the country is aggressively reducing air pollution by replacing coal-fired electricity generation facilities with natural gas. Clearly, the U.S. is competing for this market share and as a result, is relieving some pressure on the North American supply imbalance.

At home in Alberta, new demand for natural gas is growing through both industrial and residential sources but is inadequate in size to truly accommodate the clear and transparent potential of Canada's clean and abundant natural gas resources. Canada needs access to export markets and we are hopeful that collaboratively our industry, our policy makers and our citizens of this nation will create the environment to provide country's like China with an energy solution that will materially impact the emissions intensity of our planet.

In the meantime, the current winter has been cold throughout North America. This has resulted in record storage withdrawals in the U.S. and significant withdrawals in Canada, which has helped bring current storage to the low end of the five-year average range. As always, weather will continue to be the wild card in natural gas demand, while extreme weather events have become more prevalent and will continue to impact demand in gas-consuming areas.

As a result, we forecast continued volatility in AECO natural gas pricing in the short-term. As such, we have prudently minimized the impact of weak AECO pricing and insulated our adjusted funds flow in 2018. We have hedged approximately 50% of our forecasted natural gas production at an AECO price of $3.07 per mcf, equal to 220% of current AECO calendar 2018 strip pricing. Additionally, we have diversified approximately 25% of our forecasted 2018 natural gas production to other sales points in North America such as Dawn, Chicago and Ventura. This prudent reduction in AECO exposure has resulted in only 23% of our forecasted natural gas volumes and nine percent of our 2018 forecasted petroleum and natural gas revenues exposed to the AECO spot market.

At current commodity futures pricing it is in our best interest to focus on creating incremental financial flexibility by allocating 30-40% of our adjusted funds flow to debt repayment and the remainder to a moderate capital program. We will remain disciplined with our capital budget in 2018 and will focus on allocating our capital to NGL rich locations within our portfolio. With the continuing decline in natural gas prices in the past three months, we have scheduled shut-in volumes of approximately 1,700 boe per day by year-end, resulting in an annualized impact of approximately 900 boe per day. We have also elected to reduce our 2018 capital spending program to between $135 and $155 million intended to generate annual production rates between 69,000 and 71,000 boe per day. We remain focused on improving our financial flexibility, as such we are targeting a total payout ratio of 60% to 70% and will apply the excess adjusted funds flow of between $60 and $80 million to reduce our total debt.

Bonavista wishes to announce that Ms. Margaret Mackenzie will retire as a director of the Company effective today. Ms. Mackenzie has served on the Board of Directors since 2006 and over her 12 year tenure, has provided valuable guidance and oversight particularly on the audit and compensation committees. We would like to thank her for her service to Bonavista and wish her all the best in the future. Also, after six years as Executive Chairman, Mr. Keith MacPhail will step away from this role to Non-Executive Chairman of the Board effective today.

We thank our employees for their commitment and dedication, our Board of Directors for their guidance and our shareholders for their long-term support. We are confident that we have the people and assets to weather the temporary pressure on our industry and strengthen our financial flexibility as we position ourselves for growth in a stronger economic environment.

On behalf of the Board of Directors

Keith A. MacPhail
Chairman

Jason E. Skehar
President and Chief Executive Officer

March 1, 2018
Calgary, Alberta

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis ("MD&A") is dated March 1, 2018 and should be read in conjunction with the audited consolidated financial statements (the "financial statements") for the year ended December 31, 2017, together with the notes related thereto, for a full understanding of the financial position and results of operations of Bonavista Energy Corporation's (the "Corporation" or "Bonavista"). Additional information relating to Bonavista, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com *or can be obtained from Bonavista's website at* www.bonavistaenergy.com.

The audited consolidated financial statements and comparative information for the year ended December 31, 2017 have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standard Board ("IASB"). The MD&A contains Non-GAAP measures and forward-looking information. The MD&A should be read in conjunction with Bonavista's disclosures under the heading "Non-GAAP Measures", "Additional Operational Measures" and "Forward-looking Statements", included at the end of the MD&A.

Operations - Bonavista's exploration and development program of $289.0 million led to the drilling of 31 (30.2 net) wells in the West Central core area and 30 (26.5 net) wells in the Deep Basin core area for the year ended December 31, 2017. Consistent with Bonavista's asset concentration strategy, exploration and development activities for the year were focused on the development of Bonavista's core areas. The wells drilled in the West Central core area included 15 (14.5 net) Spirit River wells and 16 (15.7 net) Glauconite wells. The wells drilled in the Deep Basin core area included 23 (21.8 net) Spirit River wells, three (2.5 net) Bluesky wells, three (1.2 net) Cardium wells and one (1.0 net) Ellerslie well.

For 2018, with subdued natural gas pricing, Bonavista remains focused on creating incremental financial flexibility by allocating between 30% and 40% of adjusted funds flow to total debt repayment and the remainder to a moderate capital program. This capital program will be disciplined and focused on liquids rich locations within Bonavista's core areas and is budgeted to be between $135 million and $155 million, which will generate production between 69,000 and 71,000 boe per day.

Reserves and Performance Measures - Reserves estimates have been calculated in compliance with National Instrument 51-101 Standards of Disclosure ("NI 51-101"). Independent third-party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") evaluated 100% of Bonavista's total net present value reserves in their report dated January 31, 2018 and effective December 31, 2017. The reserve estimates contained in the following tables represent Bonavista's gross reserves at December 31, 2017 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.

Reserves(1)(2)	**Natural Gas**(3)	**Oil**(4)	**Natural Gas Liquids**	**Total Reserves**(5)
	(mmcf)	(mbbls)	(mbbls)	(mboe)
Proved				
Proved Producing	642,376	4,489	43,267	154,819
Proved Non-Producing	33,151	325	1,808	7,658
Proved Undeveloped	479,484	1,548	31,069	112,531
Total Proved	**1,155,012**	**6,362**	**76,145**	**275,008**
Probable	722,009	2,905	39,495	162,735
Proved plus Probable	**1,877,021**	**9,266**	**115,640**	**437,743**
Proved reserve life index (years)(6)				**10.3**
Proved plus Probable reserve life index (years)(6)				**15.2**

(1) Bonavista's working interest reserves are based on the GLJ reserve report dated January 31, 2018, GLJ reserve estimates based on forecast prices and costs as of January 1, 2018.
(2) Amounts may not add due to rounding.
(3) Includes conventional natural gas, shale natural gas and coal bed methane.
(4) Includes light, medium, heavy and tight oil.
(5) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Additionally, given that the value ratio based on the current price of crude oil, as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.
(6) Calculated based on the amount for the relevant reserve category divided by the 2018 production forecast prepared by GLJ.

Reserve Reconciliation(1)	**Proved**	**Probable**	**Proved plus Probable**
	(mboe)	(mboe)	(mboe)
Balance as at December 31, 2016	273,183	141,022	414,205
Extensions and Improved Recovery(2)	**32,015**	**26,318**	**58,334**
Technical Revisions	**(2,532)**	**(5,500)**	**(8,032)**
Acquisitions	**1,759**	**3,833**	**5,592**
Dispositions	**(1,902)**	**(1,806)**	**(3,708)**
Economic Factors	**(1,245)**	**(1,133)**	**(2,378)**
Production	**(26,270)**	**—**	**(26,270)**
Balance as at December 31, 2017	**275,008**	**162,735**	**437,743**

(1) Amounts may not add due to rounding.
(2) Infill Drilling, improved recovery and extensions have been grouped with extensions and improved recovery as per NI 51-101.

Bonavista's 2017 year end proved reserves totaled 275.0 mmboe, a one percent increase when compared to the 273.2 mmboe for the year ended 2016. Proved plus probable reserves increased six percent to 437.7 mmboe when compared to 414.2 mmboe for the year ended 2016. Bonavista's proved plus probable reserve life index increased six percent to 15.2 years for the year ended 2017 compared to 14.4 years for the year ended 2016 demonstrating the sustainable balance of Bonavista's capital program, reserve additions and production levels.

The following table highlights Bonavista's proved plus probable reserves, proved plus probable finding and the development ("F&D") expenditures, proved plus probable finding, development and acquisition ("FD&A") expenditures and the associated recycle ratios:

Years ended December 31	**2017**	2016	% Change
Reserves (mboe):			
Proved producing	**154,819**	155,907	(1)%
Total proved	**275,008**	273,183	1 %
Proved plus probable	**437,743**	414,205	6 %
Capital expenditures ($ millions):			
Exploration and development	**289.0**	153.9	88 %
Dispositions, net of acquisitions	**(7.8)**	(167.9)	95 %
Total capital expenditures(1)	**281.2**	(14.0)	2,109 %
Operating Netback ($/boe)(2):			
Current year	**13.85**	13.44	3 %
Three-year weighted average	**14.55**	17.54	(17)%
Finding and Development Expenditures(5):			
Proved Producing:			
Change in F&D costs ($ thousands)	**(11,818)**	(173)	(6,731)%
Reserves additions (mboe)	**25,902**	15,831	64 %
F&D costs ($/boe)(3)	**10.70**	9.71	10 %
F&D recycle ratio(4)	**1.3**	1.4	(7)%
F&D three-year weighted costs ($/boe)(3)	**10.95**	12.04	(9)%
F&D recycle ratio three-year weighted average(4)	**1.3**	1.5	(13)%
Total Proved:			
Change in F&D costs ($ thousands)	**(41,615)**	86,377	(148)%
Reserves additions (mboe)	**28,237**	26,972	5 %
F&D costs ($/boe)(3)	**8.76**	8.91	(2)%
F&D recycle ratio(4)	**1.6**	1.5	7 %
F&D three-year weighted costs ($/boe)(3)	**8.11**	10.40	(22)%
F&D recycle ratio three-year weighted average(4)	**1.8**	1.7	6 %
Proved plus Probable:			
Change in F&D costs ($ thousands)	**75,423**	60,902	(24)%
Reserves additions (mboe)	**47,923**	30,824	55 %
F&D costs ($/boe)(3)	**7.60**	6.97	9 %
F&D recycle ratio(4)	**1.8**	1.9	(5)%
F&D three-year weighted costs ($/boe)(3)	**7.34**	9.11	(19)%
F&D recycle ratio three-year weighted average(4)	**2.0**	1.9	5 %
Finding, Development and Acquisition Expenditures(5):			
Proved Producing:			
Change in FD&A costs ($ thousands)	**(13,638)**	(2,269)	(501)%
Reserves additions (mboe)	**25,182**	18,879	33 %
FD&A costs ($/boe)(3)	**10.62**	(0.86)	1,335 %
FD&A recycle ratio(4)	**1.3**	(15.6)	108 %
FD&A three-year weighted costs ($/boe)(3)	**8.22**	9.69	(15)%
FD&A recycle ratio three-year weighted average(4)	**1.8**	1.8	— %

Years ended December 31	2017	2016	% Change
Finding, Development and Acquisition Expenditures[5]**:**			
Total Proved:			
Change in FD&A costs ($ thousands)	**(38,762)**	111,576	(135)%
Reserves additions (mboe)	**28,095**	36,004	(22)%
FD&A costs ($/boe)[3]	**8.63**	2.71	218 %
FD&A recycle ratio[4]	**1.6**	5.0	(68)%
FD&A three-year weighted costs ($/boe)[3]	**5.50**	7.81	(30)%
FD&A recycle ratio three-year weighted average[4]	**2.6**	2.2	18 %
Proved plus Probable:			
Change in FD&A costs ($ thousands)	**95,119**	(3,821)	2,589 %
Reserves additions (mboe)	**49,808**	32,756	52 %
FD&A costs ($/boe)[3]	**7.56**	(0.55)	1,475 %
FD&A recycle ratio[4]	**1.8**	(24.4)	107 %
FD&A three-year weighted costs ($/boe)[3]	**4.86**	6.42	(24)%
FD&A recycle ratio three-year weighted average[4]	**3.0**	2.7	11 %

(1) Amounts may not add due to rounding.
(2) Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, operating and transportation expenses calculated on a per boe basis.
(3) Both F&D and FD&A costs take into account reserve revisions during the year on a per boe basis (6:1).
(4) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs on a per boe basis.
(5) Calculated using Bonavista's working interest reserves.

Bonavista considers its recycle ratio to be an important measure of profitability, delivering a FD&A recycle ratio of 1.8:1 for proved plus probable reserves despite negative technical reserve revisions of 8,032 mboe. Additional reserves disclosure tables, as required under NI 51-101, are contained in Bonavista's Annual Information Form that will be filed on SEDAR.

***Financial and operating highlights* -** The following is a summary of key financial and operating results for the respective periods:

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
($ thousands, except per boe and share amounts where noted)						
Production:						
Natural gas (mmcf/d)	**318**	278	14 %	**306**	280	9 %
Natural gas liquids (bbls/d)	**19,284**	19,941	(3)%	**18,794**	18,247	3 %
Oil (bbls/day)[1]	**2,463**	3,069	(20)%	**2,415**	3,708	(35)%
Total production (boe/d)	**74,799**	69,339	8 %	**72,156**	68,550	5 %
Product prices[2]:						
Natural gas ($/mmcf)	**3.14**	3.31	(5)%	**3.05**	3.13	(3)%
Natural gas liquids ($/bbl)	**28.47**	25.83	10 %	**27.29**	19.97	37 %
Oil ($/bbl)	**59.49**	68.80	(14)%	**57.80**	61.89	(7)%
Production revenues	**147,188**	141,842	4 %	**553,002**	445,434	24 %
per boe	**21.39**	22.24	(4)%	**21.00**	17.75	18 %
Production revenues and realized gains on financial instrument commodity contracts	**155,873**	151,525	3 %	**578,568**	537,206	8 %
per boe	**22.65**	23.75	(5)%	**21.97**	21.41	3 %
Royalties	**8,066**	12,767	(37)%	**41,677**	36,903	13 %
per boe	**1.17**	2.00	(42)%	**1.58**	1.47	7 %
% of Production revenues	**5.5%**	9.0%	(4)%	**7.5%**	8.3%	(1)%

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
($ thousands, except per boe and share amounts where noted)						
Operating expenses	**38,343**	36,700	4 %	**147,165**	140,592	5 %
per boe	**5.57**	5.75	(3)%	**5.59**	5.60	— %
Transportation expenses	**7,584**	5,512	38 %	**24,871**	22,566	10 %
per boe	**1.10**	0.86	28 %	**0.94**	0.90	4 %
General and administrative expenses	**6,819**	6,948	(2)%	**24,749**	27,138	(9)%
per boe	**0.99**	1.09	(9)%	**0.94**	1.08	(13)%
Share-based compensation expenses	**2,614**	2,058	27 %	**15,702**	8,994	75 %
per boe	**0.38**	0.32	19 %	**0.60**	0.36	67 %
Depreciation, depletion, amortization and impairment	**280,514**	64,313	336 %	**469,555**	319,845	47 %
per boe	**40.76**	10.08	304 %	**17.83**	12.75	40 %
Net finance costs(3)	**16,727**	26,878	(38)%	**21,209**	44,257	(52)%
per boe	**2.43**	4.21	(42)%	**0.81**	1.76	(54)%
Interest expense	**8,953**	10,856	(18)%	**38,118**	45,616	(16)%
per boe	**1.30**	1.70	(24)%	**1.45**	1.82	(20)%
Deferred income taxes (recovery)	**(55,660)**	748	7,541 %	**(16,251)**	(38,929)	(58)%
per boe	**(8.09)**	0.12	6,842 %	**(0.62)**	(1.55)	(60)%
Net loss	**(159,149)**	(12,021)	1,224 %	**(27,930)**	(95,998)	(71)%
per boe	**(23.13)**	(1.88)	1,130 %	**(1.06)**	(3.83)	(72)%
per share - basic	**(0.62)**	(0.05)	1,140 %	**(0.11)**	(0.40)	(73)%
Dividends declared	**2,518**	2,493	1 %	**10,040**	13,891	(28)%
per share	**0.01**	0.01	— %	**0.04**	0.06	(33)%
Adjusted funds flow	**86,108**	78,742	9 %	**301,988**	264,391	14 %
per boe	**12.51**	12.34	1 %	**11.47**	10.54	9 %
per share - basic	**0.33**	0.31	6 %	**1.18**	1.11	6 %

(1) Oil includes light, medium, heavy and tight oil.
(2) Product prices include realized gains on financial instrument commodity contracts.
(3) Includes interest expense.

Production - Production volumes for the year ended December 31, 2017 averaged 72,156 boe per day, a five percent increase compared to an average of 68,550 boe per day in the same period of 2016. The increase in average production volumes resulted from increased capital spending on the development of liquids rich natural gas properties leading to new well production growth in excess of natural production declines and the acquisition of liquids rich natural gas weighted assets acquired in the fourth quarter of 2016. These increases were offset by the temporary shut-in of wells in response to low natural gas pricing in the second half of 2017 and natural production declines in non-core areas. Production volumes averaged 74,799 boe per day for the fourth quarter ended December 31, 2017, an eight percent increase when compared to an average of 69,339 boe per day for the fourth quarter of 2016, for similar reasons as stated above.

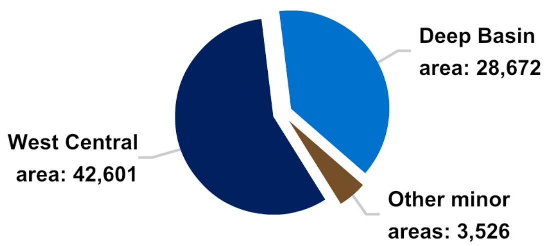
For the year ended December 31, 2017, natural gas production averaged 306 mmcf per day, a nine percent increase compared to an average of 280 mmcf per day for the year ended December 31, 2016. The increase in natural gas production was largely due to new well production growth and acquisitions completed in the fourth quarter of 2016 in the natural gas weighted Deep Basin core area, offset by the disposition of non-core natural gas weighted properties in the second half of 2016. Natural gas liquids production was 18,794 bbls per day for the year ended December 31, 2017, a three percent increase when compared to 18,247 bbls per day for the same period of 2016. The increase in natural gas liquids production was largely due to the acquisition of liquids rich natural gas weighted assets in the fourth quarter of 2016 in addition to strong liquids yields on new well production. Oil production decreased 35% to 2,415 bbls per day for the year ended December 31, 2017 from 3,708 bbls per day in the same period of 2016 as a result of non-core light-oil weighted asset dispositions and natural production declines in mature light oil assets as Bonavista continues to focus exploration and development activities to lower cost, liquids rich natural gas properties.

For the three months ended December 31, 2017, natural gas production increased 14% to 318 mmcf per day compared to 278 mmcf per day in the same period of 2016, for similar reasons as stated above. Natural gas liquids production decreased three percent to 19,284 bbls per day for the three months ended December 31, 2017 from 19,941 bbls per day for the same period of 2016 due to capital activity focused in the Deep Basin core area which produces a higher ratio of natural gas to natural gas liquids. Oil production decreased 20% to 2,463 bbls per day for the three months ended December 31, 2017 from 3,069 bbls per day for the same period of 2016, for similar reasons as stated above.

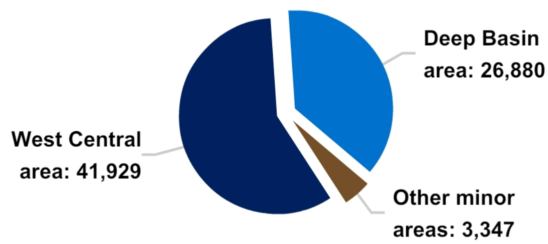
The following table highlights Bonavista's production by product for the three months and years ended December 31:

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
Natural gas (mmcf/day)	**318**	278	14 %	**306**	280	9 %
Natural gas liquids (bbls/day)	**19,284**	19,941	(3)%	**18,794**	18,247	3 %
Oil (bbls/day)	**2,463**	3,069	(20)%	**2,415**	3,708	(35)%
Total oil equivalent (boe/day)	**74,799**	69,339	8 %	**72,156**	68,550	5 %

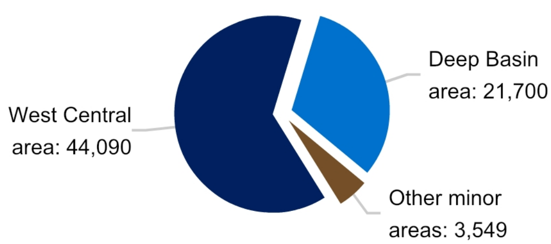
Production by Core Area (boe/day)
(Three months ended December 31, 2017)



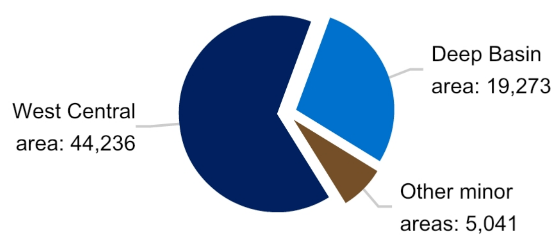
Production by Core Area (boe/day)
(Year ended December 31, 2017)



Production by Core Area (boe/day)
(Three months ended December 31, 2016)



Production by Core Area (boe/day)
(Year ended December 31, 2016)



Bonavista's current production is approximately 72,000 boe per day the composition of which is 75% natural gas, 22% natural gas liquids and three percent light oil.

***Production revenues* -** For the year ended December 31, 2017, production revenues, excluding the impact of financial instrument commodity contracts, increased 24% to $553.0 million compared to $445.4 million for the year ended December 31, 2016. The increase was due to an 18% increase in commodity prices on a per boe basis in addition to the impact of a five percent increase in average production volumes. The increase in commodity prices was largely due to a modest recovery in commodity prices throughout the first half of 2017, with natural gas prices weakening in the second half of 2017. In particular, the year-over-year improvement of natural gas liquids prices has been a driver in Bonavista's production revenue growth, with propane prices returning to levels similar to 2014. For the three months ended December 31, 2017, production revenues, excluding the impact of financial instrument commodity contracts, increased four percent to $147.2 million, compared to $141.8 million for the same period of 2016. The increase was due to an eight percent increase in average production volumes partially offset by a four percent decrease in commodity prices on a per boe basis.

Natural gas prices, excluding the impact of financial instrument commodity contracts, increased 10% to $2.64 per mcf for the year ended December 31, 2017, compared to $2.41 per mcf for the same period of 2016. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, increased 51% to $30.34 per bbl for the year ended December 31, 2017, compared to $20.11 per bbl for the same period of 2016. Oil prices, excluding the impact of financial instrument commodity contracts, increased 20% to $56.82 per bbl for the year ended December 31, 2017, compared to $47.25 per bbl for the same period of 2016. Natural gas prices, excluding the impact of financial instrument commodity contracts, for the three months ended December 31, 2017, decreased 19% to $2.46 per mcf compared to $3.03 per mcf for the same period of 2016. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, increased 31% to $34.49 per bbl for the three months ended December 31, 2017, compared to $26.36 per bbl in the same period of 2016. Oil prices, excluding the impact of financial instrument commodity contracts, increased 11% to $62.24 per bbl for the three months ended December 31, 2017, compared to $56.23 per bbl for the comparable period of 2016.

Consistent with Bonavista's objective to protect adjusted funds flow, financial instrument commodity contracts have partially mitigated Bonavista's exposure to the weak and volatile commodity price environment over the past five years. For the year ended December 31, 2017, a gain of $25.6 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $91.8 million for the year ended December 31, 2016. Similarly, for the three months ended December 31, 2017, a gain of $8.7 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $9.7 million for the comparable period of 2016.

For the year ended December 31, 2017, natural gas prices, including the impact of financial instrument commodity contracts, decreased three percent to $3.05 per mcf compared to $3.13 per mcf for the same period of 2016. For the year ended December 31, 2017, natural gas liquids prices, including the impact of financial instrument commodity contracts, increased 37% to $27.29 per bbl, compared to $19.97 per bbl realized for the same period of 2016. Oil prices, including the impact of financial instrument commodity contracts, decreased seven percent to $57.80 per bbl for the year ended December 31, 2017, when compared to $61.89 per bbl realized for the comparable period of 2016. Natural gas prices, including the impact of financial instrument contracts, for the three months ended December 31, 2017, decreased five percent to $3.14 per mcf compared to $3.31 per mcf for the same period of 2016. For the three months ended December 31, 2017, natural gas liquids prices, including the impact of financial instrument commodity contracts, increased 10% to $28.47 per bbl, from $25.83 per bbl realized for the comparable period of 2016. Oil prices, including the impact of financial instrument commodity contracts, for the fourth quarter of 2017 were $59.49 per bbl, a 14% decrease when compared to $68.80 per bbl realized for the same period of 2016.

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

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
Natural gas ($/mcf):				
Production revenues	**2.46**	3.03	**2.64**	2.41
Realized gains on financial instrument commodity contracts	**0.68**	0.28	**0.41**	0.72
Realized price including financial instrument commodity contracts	**3.14**	3.31	**3.05**	3.13
Natural gas liquids ($/bbl):				
Production revenues	**34.49**	26.36	**30.34**	20.11
Realized losses on financial instrument commodity contracts	**(6.02)**	(0.53)	**(3.05)**	(0.14)
Realized price including financial instrument commodity contracts	**28.47**	25.83	**27.29**	19.97
Oil ($/bbl):				
Production revenues	**62.24**	56.23	**56.82**	47.25
Realized gains (losses) on financial instrument commodity contracts	**(2.75)**	12.57	**0.98**	14.64
Realized price including financial instrument commodity contracts	**59.49**	68.80	**57.80**	61.89
Total ($/boe):				
Production revenues	**21.39**	22.24	**21.00**	17.75
Realized gains on financial instrument commodity contracts	**1.26**	1.51	**0.97**	3.66
Realized price including financial instrument commodity contracts	**22.65**	23.75	**21.97**	21.41

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 and protect adjusted funds flow, 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 oil, natural gas liquids and natural gas 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, 2017, Bonavista had entered into the following costless collars to sell oil and natural gas:

Volume		Average Price	Contract	Term
Natural gas contracts				
5,000	gjs/d	CDN $2.90 - CDN $3.10	AECO - Costless Collar	January 1, 2018 - March 31, 2018
20,000	gjs/d	CDN $2.60 - CDN $3.00	AECO - Costless Collar	January 1, 2018 - December 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10	AECO - Costless Collar	November 1, 2018 - March 31, 2019
Oil contract				
250	bbls/d	CDN $65.00 - CDN $ 70.02	WTI - Costless Collar	January 1, 2019 - December 31, 2020

At December 31, 2017, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas contracts				
45,000	gjs/d	CDN $3.08	AECO - Swap	January 1, 2018 - March 31, 2018
40,000	gjs/d	CDN $2.88	AECO - Swap	January 1, 2018 - December 31, 2018(1)(4)
10,000	gjs/d	CDN $2.69	AECO - Swap	January 1, 2018 - March 31, 2019
24,000	gjs/d	CDN $2.20	AECO - Swap	April 1, 2018 - October 1, 2018
20,000	gjs/d	CDN $2.68	AECO - Swap	April 1, 2018 - December 31, 2018
10,000	gjs/d	CDN $2.70	AECO - Swap	April 1, 2018 - December 31, 2019
5,000	gjs/d	CDN $3.05	AECO - Swap	November 1, 2018 - March 31, 2019
20,000	mmbtu/d	US ($0.68)	AECO - Basis Swap	January 1, 2018 - December 31, 2018
23,695	mmbtu/d	US ($1.25)	AECO - Basis Swap	April 1, 2018 - October 31, 2018
10,000	mmbtu/d	US ($0.98)	AECO - Basis Swap	January 1, 2019 - December 31, 2021
10,000	mmbtu/d	US ($0.16)	DAWN - Basis Swap	January 1, 2018 - December 31, 2018
20,000	mmbtu/d	US $2.97	NYMEX - Swap	January 1, 2018 - December 31, 2018
5,000	mmbtu/d	US $2.70	NYMEX - Swap	April 1, 2018 - October 1, 2018
10,000	mmbtu/d	US $4.00	NYMEX - Sold Call	January 1, 2018 - December 31, 2018
10,000	mmbtu/d	US $3.75	NYMEX - Sold Call	January 1, 2019 - December 31, 2021
Natural gas liquids contracts				
500	bbls/d	US $31.50	MTB BT - Swap	January 1, 2018 - March 31, 2018(2)
1,000	bbls/d	US $28.77	MTB BT - Swap	January 1, 2018 - December 31, 2018(2)
500	bbls/d	US $32.76	MTB BT - Swap	January 1, 2018 - December 31, 2019(2)
500	bbls/d	US $29.40	MTB BT - Swap	April 1, 2018 - December 31, 2018(2)
1,000	bbls/d	US $32.13	MTB BT - Swap	January 1, 2019 - December 31, 2019(2)
750	bbls/d	US $34.86	MTB BT - Swap	January 1, 2019 - December 31, 2020(2)
1,000	bbls/d	US $23.04	CNWY PN - Swap	January 1, 2018 - March 31, 2018(3)
1,500	bbls/d	US $21.18	CNWY PN - Swap	January 1, 2018 - December 31, 2018(3)
1,000	bbls/d	US $25.25	CNWY PN - Swap	January 1, 2018 - December 31, 2019(3)
500	bbls/d	US $29.40	CNWY PN - Swap	April 1, 2018 - June 30, 2018(3)
500	bbls/d	US $22.05	CNWY PN - Swap	July 1, 2018 - December 31, 2018(3)
1,250	bbls/d	US $25.91	CNWY PN - Swap	January 1, 2019 - December 31, 2019(3)
250	bbls/d	US $29.40	CNWY PN - Swap	January 1, 2019 - December 31, 2020(3)

Oil contracts				
1,000	bbls/d	US $50.00	WTI - Swap	January 1, 2018 - December 31, 2018
1,500	bbls/d	CDN $69.82	WTI - Swap	January 1, 2018 - December 31, 2019
1,500	bbls/d	CDN $70.17	WTI - Swap	January 1, 2018 - December 31, 2018
1,000	bbls/d	CDN $70.25	WTI - Swap	January 1, 2019 - December 31, 2019
500	bbls/d	CDN $65.00	WTI - Sold Call	January 1, 2018 - December 31, 2018

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 30,000 gjs/d on the last trade date of each month for the duration of the contract.
(2) Mont Belvieu 65 nC4/35 iC4 price.
(3) Conway propane price.
(4) Includes an extendable feature on 10,000 gjs/d at $2.75 gjs/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2019.

Subsequent to December 31, 2017, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
10,000	mmbtu/d	US $2.73	NYMEX - Sold Call	March 1, 2018 - December 31, 2018
15,000	mmbtu/d	US $2.74	NYMEX - Swap	April 1, 2018 - October 31, 2018
10,000	mmbtu/d	US $2.91	NYMEX - Swap	January 1, 2019 - December 31, 2019
10,000	mmbtu/d	US ($1.00)	AECO - Basis Swap	January 1, 2019 - December 31, 2019
1,000	bbls/d	US $54.60	WTI - Sold Call	January 1, 2020 - December 31, 2020
250	bbls/d	US $24.78	CNWY PN - Swap	January 1, 2020 - December 31, 2020[(1)]

(1) Conway propane price.

At December 31, 2017, the fair market value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $26.2 million compared to a net liability of $81.4 million at December 31, 2016. Of the $26.2 million net asset balance at December 31, 2017, a net asset of $26.4 million relates to financial instrument commodity contracts with term dates within one year and a net liability of $0.2 million relates to financial instrument commodity contracts with term dates beyond one year.

For the year ended December 31, 2017, the financial instrument commodity contracts in place under Bonavista's risk management program 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 same period of 2016, the financial instrument commodity contracts in place resulted in a net loss of $70.2 million, consisting of a realized gain of $91.8 million and an unrealized loss of $161.9 million. The realized gain of $91.8 million consisted of a $72.8 million gain on natural gas commodity derivative contracts, a $0.9 million loss on natural gas liquids commodity derivative contracts and a $19.9 million gain on oil commodity derivative contracts.

For the three months ended December 31, 2017, the financial instrument commodity contracts in place under Bonavista's risk management program 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. For the same period of 2016, the financial instrument commodity contracts in place resulted in a net loss of $90.1 million, consisting of a realized gain of $9.7 million and an unrealized loss of $99.8 million. The realized gain of $9.7 million consisted of a $7.1 million gain on natural gas commodity derivative contracts, a $1.0 million loss on natural gas liquids commodity derivative contracts and a $3.5 million gain on oil commodity derivative contracts.

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

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
($ thousands)				
Natural gas	**19,995**	7,098	**45,660**	72,839
Natural gas liquids	**(10,688)**	(964)	**(20,951)**	(931)
Oil	**(622)**	3,549	**857**	19,864
Realized gains on financial instrument commodity contracts	**8,685**	9,683	**25,566**	91,772
Unrealized gains (losses) on financial instrument commodity contracts	**(9,187)**	(99,807)	**107,614**	(161,930)
Net gains (losses) on financial instrument commodity contracts	**(502)**	(90,124)	**133,180**	(70,158)

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 loss and comprehensive loss at December 31, 2017:

	Change in AECO	
($ thousands)	Increase $0.10	Decrease $0.10
Natural Gas Commodity Contracts	(10,537)	10,475

	Change in WTI	
($ thousands)	Increase $1.00	Decrease $1.00
Oil Commodity Contracts	(2,096)	2,003

In addition to these financial instrument commodity contracts in place, Bonavista also entered into the following physical contracts to sell natural gas as at December 31, 2017:

Volume		Price	Term
20,000	gjs/d	CDN $3.00	January 1, 2018 - December 31, 2018(1)
10,000	gjs/d	CDN $2.75	April 1, 2018 - October 31, 2018(2)

(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.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 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 oil, natural gas liquids and natural gas prices received are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar oil, natural gas liquids and natural gas 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$/US$
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

Subsequent to December 31, 2017, Bonavista entered into the following contracts to mitigate the risk associated with foreign exchange exposure:

Settlement date	Contract	Notional US$	CDN$/US$
2018(1)	US$ purchased forward	$9,314,400	1.2288
2019(1)	US$ purchased forward	$9,314,400	1.2288

(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 in both 2018 and 2019.

The fair value recorded on the consolidated statement of financial position for these financial instrument contracts at December 31, 2017 was a net liability of $19.3 million of which all $19.3 million relates to financial instrument contracts with term dates beyond one year.

For the year ended December 31, 2017, an unrealized loss of $23.7 million was recorded on the consolidated statement of loss and comprehensive loss, compared to an unrealized loss of $66.4 million in the same period of 2016. The unrealized loss for the year ended December 31, 2017, resulted from the strengthening of the CDN dollar relative to the US dollar, which at December 31, 2017 was $1.2573 CDN$/US$ compared to the December 31, 2016 rate of $1.3427 CDN$/US$. At December 31, 2017 a $0.01 change in the CDN$/US$ exchange rate would have had an absolute impact of approximately $2.9 million on net loss and comprehensive loss.

For the three months ended December 31, 2017, an unrealized gain of $6.6 million was recorded in the consolidated statement of loss and comprehensive loss, compared to an unrealized gain of $7.7 million in the same period of 2016. The unrealized gain for the three months ended December 31, 2017, resulted from the weakening of the CDN dollar relative to the US dollar, which at December 31, 2017 was $1.2573 CDN$/US$ compared to the September 30, 2017 rate of $1.2471 CDN$/US$.

Royalties **-** For the year ended December 31, 2017 royalties increased 13% to $41.7 million from $36.9 million for the year ended December 31, 2016, largely attributable to a five percent increase in production volumes and an 18% increase in production revenues on a per boe basis. Royalties as a percentage of production revenues were 7.5% for the year ended December 31, 2017 compared to 8.3% of production revenues for the year ended December 31, 2016. The decrease in royalties as a percentage of production revenues for the year ended December 31, 2017, was largely due to prior period natural gas crown royalty adjustments, somewhat offset by a 24% increase in production revenues.

Natural gas royalties as a percentage of natural gas production revenues for the year ended December 31, 2017 were negative 0.2% compared to 3.0% for the year ended December 31, 2016. The decrease in natural gas royalties as a percentage of natural gas revenues was due to prior period natural gas crown royalty adjustments and the impact of drilling activity throughout 2017 focused on crown lands which carry lower gas royalty encumbrances, offset by the impact of higher average reference pricing used in crown royalty calculations. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the year ended December 31, 2017 were 17.5% compared to 17.3% for the comparable period of 2016. Oil royalties as a percentage of oil production revenues for the year ended December 31, 2017 were higher at 11.5% compared to 9.9% for the year ended December 31, 2016, as a result of higher oil crown royalty obligations on light oil assets acquired in the fourth quarter of 2016.

For the three months ended December 31, 2017, royalties decreased 37% to $8.1 million from $12.8 million for the comparable period of 2016. Royalties as a percentage of production revenues were 5.5% for the three months ended December 31, 2017 compared to 9.0% for the same period of 2016. The decrease in royalties on an absolute basis and as a percentage of production revenues was largely due to the prior period natural gas crown royalty adjustments.

For the three months ended December 31, 2017, natural gas royalties as a percentage of natural gas production revenues were negative 5.8% compared to 3.3% for the three months ended December 31, 2016, resulting from prior period natural gas crown royalty adjustments. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the three months ended December 31, 2017 were relatively consistent at 17.8% compared to 17.9% for the same period of 2016. Oil royalties as a percentage of oil production revenues for the three months ended December 31, 2017 decreased to 9.4% from 10.1% for the comparative 2016 period, as a result of prior period crown royalty adjustments.

The following table highlights Bonavista's royalties by product for the three months and years ended December 31:

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
Natural gas ($/mcf):						
Royalties	**(0.14)**	0.10	(240)%	**—**	0.07	(100)%
% of Production revenues[1]	**(5.8)%**	3.3%	(9.1)%	**(0.2)%**	3.0%	(3.2)%
Natural gas liquids ($/bbl):						
Royalties	**6.13**	4.71	30 %	**5.31**	3.48	53 %
% of Production revenues[1]	**17.8 %**	17.9%	(0.1)%	**17.5 %**	17.3%	0.2 %
Oil ($/bbl):						
Royalties	**5.87**	5.66	4 %	**6.51**	4.68	39 %
% of Production revenues[1]	**9.4 %**	10.1%	(0.7)%	**11.5 %**	9.9%	1.6 %
Total ($/boe):						
Royalties	**1.17**	2.00	(42)%	**1.58**	1.47	7 %
% of Production revenues[1]	**5.5 %**	9.0%	(3.5)%	**7.5 %**	8.3%	(0.8)%

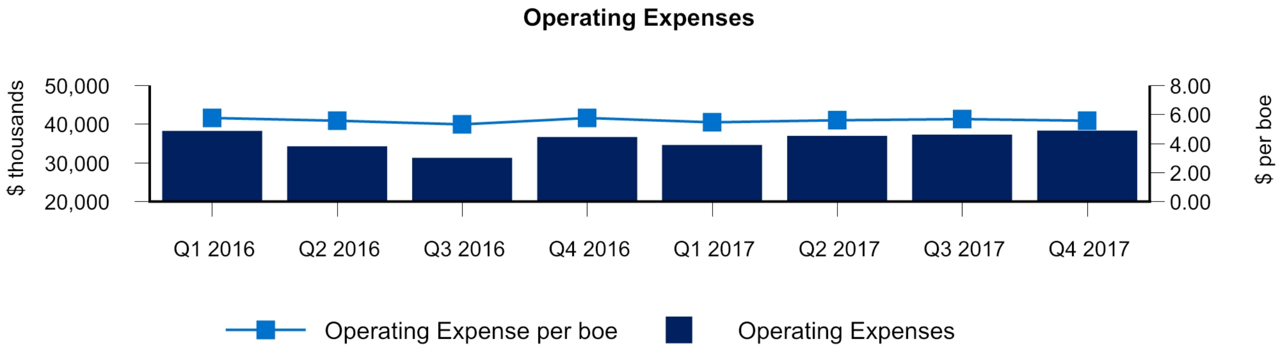
(1) % of production revenues excludes gains and losses on financial instrument commodity contracts.

Operating expenses **-** For the year ended December 31, 2017, operating expenses increased five percent to $147.2 million compared to $140.6 million for the year ended December 31, 2016. On a per boe basis, operating expenses remained relatively consistent at $5.59 per boe for the year ended December 31, 2017 compared to $5.60 per boe for the year ended December 31, 2016. The increase in operating expenses on an absolute basis was primarily due to a five percent increase in production volumes in addition to temporary shut-ins occurring in the second half of 2017 in response to low natural gas pricing and turnaround activities. These production curtailments impact operating costs on a per boe basis as fixed costs are spread amongst fewer producing barrels of oil equivalent.

Operating expenses for the three months ended December 31, 2017 increased four percent to $38.3 million compared to $36.7 million for the same period of 2016. On a per boe basis, operating expenses decreased three percent to $5.57 per boe for the three months ended December 31, 2017 compared to $5.75 per boe for the comparable period of 2016. The increase in operating expenses on an absolute basis resulted from an eight percent increase in production volumes. The decrease in operating expenses on a per boe basis was due to Bonavista's continued focus of allocating capital to lower operating cost structures.

The following table highlights Bonavista's operating expenses for the three months and years ended December 31:

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
Total ($/boe)	**5.57**	5.75	(3)%	**5.59**	5.60	— %



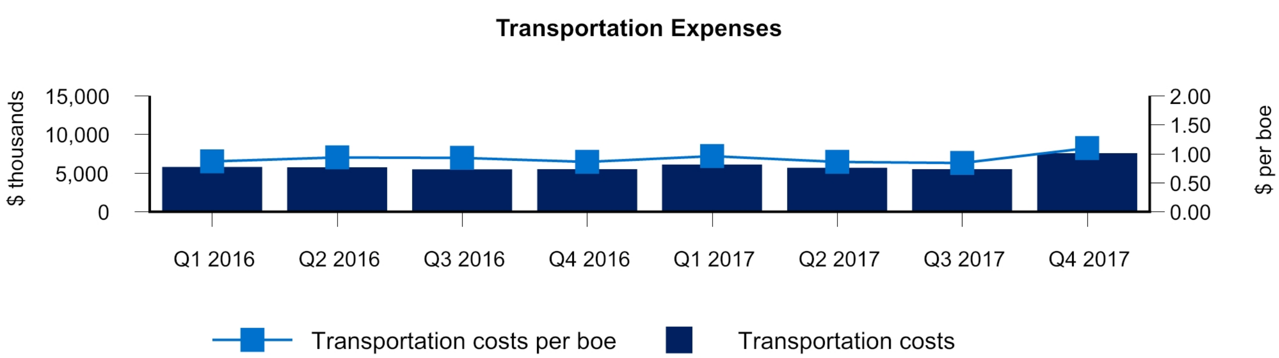
Transportation expenses **-** For the year ended December 31, 2017, transportation expenses increased 10% to $24.9 million compared to $22.6 million for the year ended December 31, 2016. On a per boe basis, transportation expenses increased four percent to $0.94 per boe for the year ended December 31, 2017 compared to $0.90 per boe for the year ended December 31, 2016. The increase in transportation expenses, on an absolute and per boe basis, was largely due to TransCanada Long Term Fixed Price ("LTFP") service commencing on November 1, 2017 offset by the disposition of non-core properties with higher associated transportation rates and changes to certain natural gas liquids and oil contracts effective April 1, 2017.

Transportation expenses for the three months ended December 31, 2017, increased 38% to $7.6 million compared to $5.5 million for the same period of 2016. On a per boe basis, transportation expenses for the three months ended December 31, 2017 increased 28% to $1.10 per boe from $0.86 per boe for the comparable period of 2016. The increase in transportation costs on an absolute and per boe basis during the fourth quarter of 2017 was due to similar reasons as noted above.

With ongoing concerns over transportation constraints, Bonavista has secured firm transportation capacity to support current development plans, with firm transportation on the NGTL system. In addition to diversify natural gas delivery points beyond AECO, Bonavista has entered into a 10-year contract, with TransCanada for LTFP service, along with other producers, to transport natural gas on TransCanada's Mainline pipeline from Alberta to the Dawn market in Southern Ontario. The LTFP contract contains an early termination policy after five years with notice provided after year three.

The following table highlights Bonavista's transportation expenses for the three months and years ended December 31:

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% Change	**2017**	2016	% Change
Total ($/boe)	**1.10**	0.86	28 %	**0.94**	0.90	4 %



Operating Netbacks **-** For the year ended December 31, 2017, Bonavista's operating netback increased three percent to $13.85 per boe compared to $13.44 per boe for the year ended December 31, 2016. The increase in Bonavista's operating netback on a per boe basis for the year ended December 31, 2017 was primarily due to higher realized commodity pricing. For the three months ended December 31, 2017, Bonavista's operating netback decreased two percent to $14.81 per boe compared to $15.14 per boe for the same period of 2016, largely due to lower realized natural gas prices recognized in the fourth quarter of 2017 compared to the fourth quarter of 2016.

The following tables highlight Bonavista's operating netbacks per boe by core area for the three months and years ended December 31 ($/boe):

	Three months ended December 31, 2017			Three months ended December 31, 2016		
	West Central	Deep Basin	Total[5]	West Central	Deep Basin	Total[5]
Production revenues	**23.19**	**20.34**	**21.39**	22.58	23.03	22.24
Realized gains on financial instrument commodity contracts[1]	**—**	**—**	**1.26**	—	—	1.51
	23.19	**20.34**	**22.65**	22.58	23.03	23.75
Royalties	**1.55**	**0.72**	**1.17**	2.24	1.64	2.00
Operating expense	**5.92**	**4.41**	**5.57**	5.56	5.42	5.75
Transportation expense	**0.80**	**1.61**	**1.10**	0.60	1.43	0.86
Total operating netback[2][3]	**14.92**	**13.60**	**14.81**	14.18	14.54	15.14
Operating Margin[4]	**64%**	**67%**	**65%**	63%	63%	64%

	Years ended December 31, 2017			Years ended December 31, 2016		
	West Central	Deep Basin	Total[5]	West Central	Deep Basin	Total[5]
Production revenues	**21.93**	**20.47**	**21.00**	18.00	18.23	17.75
Realized gains on financial instrument commodity contracts[1]	**—**	**—**	**0.97**	—	—	3.66
	21.93	**20.47**	**21.97**	18.00	18.23	21.41
Royalties	**1.99**	**1.12**	**1.58**	1.69	0.86	1.47
Operating expense	**5.82**	**4.47**	**5.59**	5.47	4.21	5.60
Transportation expense	**0.68**	**1.40**	**0.94**	0.65	1.43	0.90
Total operating netback[2][3]	**13.44**	**13.48**	**13.85**	10.19	11.73	13.44
Operating Margin[4]	**61%**	**66%**	**63%**	57%	64%	63%

(1) Amounts are not allocated by area.
(2) Amounts may not add due to rounding.
(3) Operating netbacks do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Refer to "Non-GAAP measures" for additional detail.
(4) Operating margin 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. Bonavista has calculated operating margin as production revenues and realized gains and losses on financial instruments commodity contracts less royalties, operating costs and transportation costs; divided by production revenues and realized gains and losses on financial instrument commodity contracts. Refer to "Non-GAAP measures" for additional detail.
(5) Total includes amounts recorded that are not inclusive in the West Central and Deep Basin core areas.

General and administrative expenses **-** General and administrative expenses, after overhead recoveries, decreased nine percent to $24.7 million for the year ended December 31, 2017 compared to $27.1 million for the year ended December 31, 2016. The decrease in general and administration expenses on an absolute basis was due to a 99% increase in capital overhead recoveries, as a result of an expanded exploration and development program in 2017, in addition to corporate initiatives to reduce discretionary spending. On a per boe basis, general and administrative expenses decreased 13% to $0.94 per boe for the year ended December 31, 2017 compared to $1.08 per boe for the year ended December 31, 2016, due to reasons stated above in addition to a five percent increase in production volumes.

General and administrative expenses, after overhead recoveries, was $6.8 million for the three months ended December 31, 2017, a two percent decrease compared to $6.9 million for the comparable period of 2016. The decrease in general and administrative expenses on an absolute basis resulted primarily from a 41% increase in capital overhead recoveries as a result of an expanded exploration and development program. On a per boe basis, general and administration expenses decreased nine percent to $0.99 per boe for the three months ended December 31, 2017 compared to $1.09 per boe for the same period of 2016, due to reasons stated above in addition to an eight percent increase in production volumes.

Share-based compensation - Share-based compensation expense recognized in connection with Bonavista's stock option, restricted incentive award and performance incentive award plans ("long-term incentive plans"), for the year ended December 31, 2017 was $15.7 million compared to $9.0 million recognized for the year ended December 31, 2016. For the year ended December 31, 2017, $1.4 million of share-based compensation expense was capitalized to property, plant and equipment compared to $0.8 million for the same period of 2016. The increase in share-based compensation expense for the year ended December 31, 2017, largely resulted from higher average grant prices on outstanding awards, an amended vesting arrangement for restricted incentive awards granted on January 1, 2017 with the first tranche fully expensed and vested within the first six months of issue as well as a one-time restricted share award grant on January 1, 2017 to qualifying employees fully expensed and vested upon issue.

Share-based compensation expense recognized for the three months ended December 31, 2017 was $2.6 million compared to $2.1 million recognized for the same period of 2016. For the three months ended December 31, 2017 and December 31, 2016, share-based compensation expense capitalized to property, plant and equipment remained consistent at $0.2 million. Share-based compensation expense was higher for the three months ended December 31, 2017, when compared to the same periods of 2016 due to the higher fair value associated with the outstanding restricted incentive awards and performance incentive awards expensed in 2017.

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

	Three months ended December 31,				Years ended December 31,			
	2017		2016		**2017**		2016	
	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)
Share-based compensation expense	**2,614**	**0.38**	2,058	0.32	**15,702**	**0.60**	8,994	0.36

Depletion, depreciation, amortization and impairment - For the year ended December 31, 2017, depletion, depreciation, amortization and impairment expense increased 47% to $469.6 million from $319.8 million for the year ended December 31, 2016. On a per boe basis, depletion, depreciation, amortization and impairment expense was $17.83 per boe for 2017 and $12.75 per boe for 2016. The significant increase in depletion, depreciation, amortization and impairment on both an absolute and per boe basis was the result of a $215.0 million impairment charge recorded for the year ended December 31, 2017. Bonavista identified indicators of impairment in both its 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 technical reserve revisions. As such impairment tests were carried out on both CGUs resulting in a total impairment of $215.0 million, of which $28.0 million related to the British Columbia CGU and $187.0 million related to Central Alberta CGU. The impairments recorded for the year ended December 31, 2017 may be reversed at such time that the recoverable amount of the impaired CGU increases.

For the three months ended December 31, 2017, depletion, depreciation, amortization and impairment increased 336% to $280.5 million from $64.3 million for the same period of 2016. On a per boe basis, depletion, depreciation, amortization and impairment was $40.76 per boe for the three months ended December 31, 2017 compared to $10.08 per boe for the same period of 2016. The increase in depletion, depreciation, amortization and impairment on both an absolute and per boe basis was primarily due to the impact of the $215.0 million impairment charge recorded at December 31, 2017.

For the year ended December 31, 2017, depletion, depreciation and amortization expense, excluding the impact of impairment, decreased three percent to $254.6 million for the year ended December 31, 2017 from $263.2 million for the year ended December 31, 2016. On a per boe basis, depletion, depreciation and amortization expense, excluding the impact of impairment, for the year ended December 31, 2017 decreased eight percent to $9.67 per boe compared to $10.49 per boe for the year ended December 31, 2016. The decrease in depletion, depreciation and amortization expense, excluding the impact of impairment, on an absolute and per boe basis was due to a reduction in the carrying value of property, plant and equipment as a result of non-core property dispositions throughout 2016, offset by a five percent increase in production volumes on which depletion expense is based.

For the three months ended December 31, 2017, depletion, depreciation and amortization expense, excluding the impact of impairment, was consistent with the comparable 2016 period at $65.5 million and $64.3 million, respectively. On a per boe basis, depletion, depreciation and amortization expense, excluding the impact of impairment, for the three months ended December 31, 2017 was $9.52 per boe compared to $10.08 per boe for the same period of 2016.

	Three months ended December 31,				Years ended December 31,			
	2017		2016		**2017**		2016	
	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)
Depletion, depreciation and amortization expense	**65,514**	**9.52**	64,313	10.08	**254,555**	**9.67**	263,200	10.49
Impairment expense	**215,000**	**31.24**	—	—	**215,000**	**8.16**	56,645	2.26
Depletion, depreciation, amortization and impairment expense	**280,514**	**40.76**	64,313	10.08	**469,555**	**17.83**	319,845	12.75

Net financing costs **-** Net financing costs decreased to $21.2 million for the year ended December 31, 2017, from $44.3 million for the year ended December 31, 2016. Similarly for the year ended December 31, 2017 net financing costs on a per boe basis decreased to $0.81 per boe compared to net financing costs of $1.76 per boe for the year ended December 31, 2016. The decrease can be largely attributed to unrealized foreign exchange gains associated with the revaluation of Bonavista's US denominated senior unsecured notes and financial instrument contracts offset by unrealized losses on Bonavista's financial instrument contracts and realized foreign exchange losses recognized in relation to the repayment of US dollar denominated senior unsecured notes due in June and November 2017. For the year ended December 31, 2017, an $83.7 million unrealized foreign exchange gain was recognized on the revaluation of Bonavista's US denominated senior unsecured notes compared to an unrealized foreign exchange gain of $36.4 million for the year ended December 31, 2016. For the year ended December 31, 2017, a $23.7 million unrealized loss was recognized on financial instrument contracts compared to an unrealized loss on financial instrument contracts of $66.4 million for the year ended December 31, 2016.

Net financing costs, excluding non-cash amounts and the realized gain on financial instrument contracts, decreased 16% to $38.1 million for the year ended December 31, 2017, compared to $45.6 million for the year ended December 31, 2016. The decrease in net financing costs, excluding non-cash amounts and the realized gain on financial instrument contracts, was due to a 14% reduction in Bonavista's long-term debt resulting in lower associated interest costs. Net financing costs on a per boe basis, excluding non-cash amounts and the realized gain on financial instrument contracts, decreased 20% to $1.45 per boe for the year ended December 31, 2017 compared to $1.82 per boe for the year ended December 31, 2016, for the reason discussed above in addition to a five percent increase in production volumes.

Net financing costs decreased 38% to $16.7 million for the three months ended December 31, 2017, from net financing costs of $26.9 million for the same period of 2016. The decrease can be largely attributed to unrealized foreign exchange gains associated with the revaluation of Bonavista's US denominated senior unsecured notes, coupled with lower interest costs as a result of lower overall debt levels, offset by realized foreign exchange losses recognized in relation to the repayment of US dollar denominated senior unsecured notes. Similarly, for the three months ended December 31, 2017, net financing costs on a per boe basis decreased 42% to $2.43 per boe compared to $4.21 per boe recognized in the same period of 2016, for similar reasons as stated above in addition to an eight percent increase in production volumes.

Net financing costs, excluding non-cash amounts, decreased 18% to $9.0 million for the three months ended December 31, 2017, compared to $10.9 million for the three months ended December 31, 2016. The decrease in net financing costs, excluding non-cash amounts, was due to a reduction in Bonavista's long-term debt resulting in lower associated interest costs. For the three months ended December 31, 2017, net financing costs, excluding non-cash amounts, on a per boe basis decreased 24% to $1.30 per boe compared to $1.70 per boe recognized for the same period of 2016. On a per boe basis, net financing costs, excluding non-cash amounts, decreased to a greater extent than on an absolute basis due to an eight percent increase in production volumes.

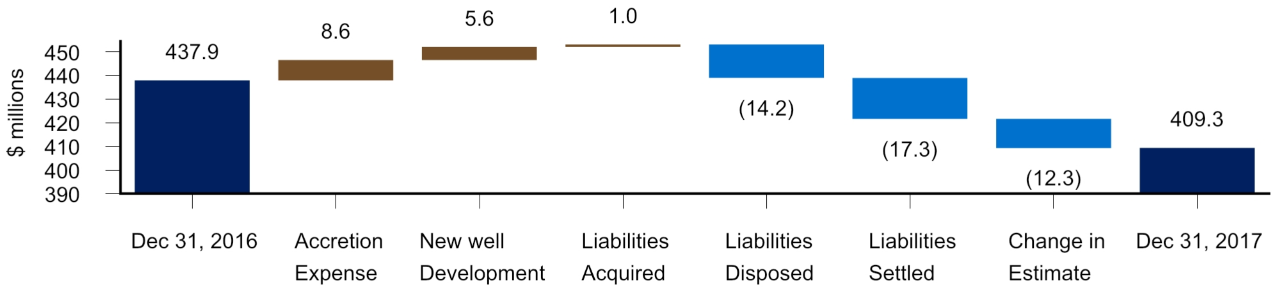
	Three months ended December 31,				Years ended December 31,			
	2017		2016		**2017**		2016	
	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)	($ thousands)	($/boe)
Net finance costs excluding non-cash amounts	**8,953**	**1.30**	10,856	1.70	**38,118**	**1.45**	45,616	1.82
Net finance costs (income) non-cash amounts	**7,774**	**1.13**	16,022	2.51	**(16,909)**	**(0.64)**	(1,359)	(0.06)
Total net finance costs	**16,727**	**2.43**	26,878	4.21	**21,209**	**0.81**	44,257	1.76

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 $409.3 million at December 31, 2017, representing a seven percent decrease when compared to the balance of $437.9 million at December 31, 2016. 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 2017, Bonavista recognized decommissioning liabilities of $5.6 million in connection with its new well development activities and $1.0 million in relation to the acquisition of certain producing properties. Reflecting the increase in Bonavista's decommissioning liability with the passage of time, accretion expense of $8.6 million was recorded for the year ended December 31, 2017 in finance costs on the consolidated statement of loss and comprehensive loss. Changes in management's estimate of the decommissioning liability caused a decrease of $12.3 million, due to revisions to Bonavista's abandonment cost estimates. Bonavista's decommissioning liability in 2017 was also reduced by $14.2 million as a result of the disposition of non-core properties and an additional reduction of $17.3 million as a result of Bonavista's active abandonment and reclamation program.

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 from adjusted funds flow and our bank credit facility. Bonavista's current Liability Management Rating (LLR) is well within the Alberta Energy Regulator guidelines.

Change in Decommissioning Liability
December 31, 2016 to December 31, 2017



Deferred income tax recovery **-** For the year ended December 31, 2017, a deferred income tax recovery of $16.3 million was recognized compared to a deferred income tax recovery of $38.9 million for the year ended December 31, 2016. For the three months ended December 31, 2017, a recovery of $55.7 million was recognized compared to a deferred income tax provision of $0.7 million recognized for the same period of 2016. The deferred income tax recovery for the year ended December 31, 2017 was higher than the recovery calculated using the statutory rate as a result of the income tax treatment of net foreign currency translation gains and losses on Bonavista's US denominated senior unsecured notes and financial instrument contracts reduced by the income tax treatment of non-deductible share-based compensation expense. The deferred income tax provision for the three months ended December 31, 2017 was higher than the provision calculated using the statutory rate due to the same reasons noted above. Bonavista made no cash payments or tax installments for the three months or year ended December 31, 2017 or for the comparative periods of 2016.

Adjusted funds flow, net loss and comprehensive loss **-** For the year ended December 31, 2017, adjusted funds flow increased 14% to $302.0 million ($1.18 per share, basic) from $264.4 million ($1.11 per share, basic) for the year ended December 31, 2016. The increase in adjusted funds flow was primarily due to an eight percent increase in production revenues, including the impact of realized gains on financial instrument commodity contracts, a 16% decrease in net financing costs, excluding non-cash amounts, partially offset by a 13% increase in royalties, a five percent increase in operating expenses and a 10% increase in transportation expenses.

For the three months ended December 31, 2017, Bonavista experienced a nine percent increase in adjusted funds flow to $86.1 million ($0.33 per share, basic) from $78.7 million ($0.31 per share, basic) for the same period of 2016. The increase in adjusted funds flow resulted primarily from a three percent increase in production revenues, including the impact of realized gains on financial instrument commodity contracts, a 37% decrease in royalties and an 18% decrease in financing costs, excluding non-cash amounts, partially offset by a four percent increase in absolute operating expenses and a 38% increase in transportation expenses.

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

	Three months ended December 31,		Years ended December 31,	
Calculation of Adjusted Funds Flow:	**2017**	2016	**2017**	2016
($ thousands)				
Cash flow from operating activities	**94,515**	70,761	**325,619**	260,792
Interest expense(1)	**(8,953)**	(10,856)	**(38,118)**	(45,616)
Decommissioning expenditures	**5,746**	6,637	**17,318**	15,309
Changes in non-cash working capital	**(5,200)**	12,200	**(2,831)**	33,906
Adjusted funds flow(2)	**86,108**	78,742	**301,988**	264,391

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) 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.

Bonavista recorded a net loss and comprehensive loss for the year ended December 31, 2017 of $27.9 million ($0.11 per share, basic) compared to a net loss and comprehensive loss of $96.0 million ($0.40 per share, basic) for the same period of 2016. The net loss and comprehensive loss was lower in 2017, largely as a result of an unrealized gain on financial instrument commodity contracts, in addition to an eight percent increase in production revenues including the impact of financial instrument commodity contracts, offset by $215.0 million in impairment charges recognized for the year ended December 31, 2017 as a result of a sustained decline in natural gas commodity prices, future development plans and technical reserve revisions.

Bonavista recorded a net loss and comprehensive loss for the three months ended December 31, 2017 of $159.1 million ($0.62 per share, basic) compared to a net loss and comprehensive loss of $12.0 million ($0.05 per share, basic) for the comparable period of 2016. The net loss and comprehensive loss was higher in 2017, largely as a result of a $215.0 million impairment charge recognized during the fourth quarter of 2017.

Capital expenditures - Capital expenditures in 2017 were focused on the development of the Glauconite and Spirit River plays in the West Central core area and the Spirit River Wilrich and Bluesky plays in the Deep Basin core area, supporting Bonavista's concentration strategy. For the year ended December 31, 2017, Bonavista's investment in exploration and development activities was $289.0 million, an 88% increase compared to the $153.9 million spent for the year ended December 31, 2016. Bonavista's exploration and development expenditures represented 96% of Bonavista's adjusted funds flow for the year ended December 31, 2017 compared to 58% for the year ended December 31, 2016. For the three months ended December 31, 2017, Bonavista's investment in exploration and development activities was $59.7 million, representing 69% of adjusted funds flow for the period and a two percent increase compared to $58.6 million for the same period of 2016. The increase in exploration and development expenditures for the year ended December 31, 2017, was supported by the improvements made in Bonavista's financial flexibility during 2016 and by proceeds received from non-core asset dispositions. Bonavista remains focused on prudent capital spending and improving capital efficiencies to optimize returns on deployed capital.

For the year ended December 31, 2017, cash proceeds from non-core dispositions totaled $21.6 million, resulting in a gain on sale of property, plant and equipment of $13.6 million and a $1.0 million gain on sale of exploration and evaluation assets. During the comparative year ended December 31, 2016, Bonavista disposed of certain non-core petroleum and natural gas rights through asset exchanges and other property dispositions for proceeds of $180.1 million, resulting in a $34.3 million gain on sale of property, plant and equipment and a $1.9 million loss on the sale of exploration and evaluation assets. During the year ended December 31, 2017, Bonavista also acquired, through property acquisitions, certain properties and petroleum and natural gas rights within its core areas for a cash consideration of $13.7 million for the year ended December 31, 2017 compared to $12.2 million for the year ended December 31, 2016.

In fourth quarter of 2016, Bonavista also completed an asset exchange whereby certain properties and petroleum and natural gas rights were acquired within the Deep Basin and West Central core areas in exchange for non-core assets in the Blueberry area of northeast British Columbia. The carrying value of the Blueberry assets disposed was $83.9 million and the fair value of the core area assets acquired was $141.6 million, resulting in a gain on the exchange of $57.7 million. The asset exchange resulted in a gain due to the fair value of the assets received being greater than the carrying value of the assets disposed, as a result of both Bonavista and its counterparty being motivated to acquire assets that aligned with strategic objectives to enhance development in core areas.

During the three months ended December 31, 2017, Bonavista successfully disposed of certain non-core assets for cash proceeds of $5.0 million compared to disposition proceeds of $120.2 million for the comparable period of 2016. During the three month period ended December 31, 2017, Bonavista acquired certain properties and petroleum and natural gas rights within its core areas for a cash consideration of $3.0 million compared to an investment of $2.6 million for the acquisition of liquids rich natural gas weighted assets in its core area certain natural gas weighted assets during the three months ended December 31, 2016. During the three months ended December 31, 2016, Bonavista also completed the asset exchange as described above.

Head office capital expenditures for the years ended December 31, 2017 and December 31, 2016 were consistent at $0.6 million.

The following table outlines capital expenditures by category for the three months and years ended December 31:

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
($ thousands)				
Land acquisitions	**1,059**	1,033	**11,620**	2,840
Geological and geophysical	**1,461**	1,049	**7,983**	4,174
Drilling and completion	**45,400**	44,973	**213,208**	121,540
Production equipment and facilities	**11,802**	11,519	**56,218**	25,317
Exploration and development expenditures	**59,722**	58,574	**289,029**	153,871
Property acquisitions(1)	**2,961**	92,929	**13,736**	102,540
Property dispositions(2)	**(5,035)**	(210,595)	**(21,577)**	(270,445)
Head office expenditures	**9**	110	**557**	604
Net capital expenditures	**57,657**	(58,982)	**281,745**	(13,430)

(1) Property acquisitions include capital expenditures that occurred by way of cash property acquisitions and non-cash property acquisitions.
(2) Property dispositions include capital proceeds that were received by way of cash property dispositions and non-cash property dispositions.

Liquidity and capital resources - At December 31, 2017, net debt was $840.2 million with a net debt to fourth quarter 2017 annualized adjusted funds flow ratio of 2.4:1. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio is calculated as net debt, defined as outstanding bank debt, senior unsecured notes and adjusted working capital, 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.

To facilitate the management of this ratio, Bonavista prepares annual adjusted funds flow and capital expenditure budgets, which are updated as necessary, and are reviewed and periodically 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 oil and natural gas 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 and transportation costs.

To maintain or adjust the capital structure, Bonavista will consider: 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; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its 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 that are outlined in note 12 of the financial statements.

The following table represents Bonavista's ratio of net debt to adjusted funds flow as follows:

Net Debt to Adjusted funds flow	**Year ended December 31, 2017**	Year ended December 31, 2016
($ thousands)		
Long-Term Debt	**800,544**	775,887
Adjusted working capital deficiency(1)	**39,629**	101,636
Total net debt(2)	**840,173**	877,523
Adjusted funds flow fourth quarter annualized	**344,432**	314,968
Total net debt to adjusted funds flow	**2.4:1**	2.8:1
Adjusted funds flow for the year ended	**301,988**	264,391
Total net debt to adjusted funds flow	**2.8:1**	3.3:1

(1) Adjusted working capital deficiency as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measure for other entities. Adjusted working capital deficiency excludes associated assets or liabilities for financial instrument commodity contracts and decommissioning liabilities.
(2) Total net debt as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar a measures with other entities. Total net debt excludes outstanding letters of credit on the bank credit facility.

On September 8, 2017, Bonavista elected to reduce the committed amount of its bank credit facility by $100 million from $600 million to $500 million. 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 facility by $100 million. The current maturity date of the bank credit facility is September 10, 2021. As at December 31, 2017 Bonavista's outstanding bank debt was $72.9 million (December 31, 2016 - nil) and outstanding letters of credit of $18.0 million (December 31, 2016 - $8.1 million), which reduce the available borrowing capacity on its bank credit facility. For the year ended December 31, 2017, borrowing costs averaged 3.6% (December 31, 2016 - 3.2%).

Bonavista's senior unsecured notes totaled $729.0 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% for the years ended December 31, 2017 and 2016. The senior unsecured notes have a weighted average life of 4.25 years with maturity dates ranging from November 2, 2020 to May 23, 2025.

At December 31, 2017 Bonavista was in compliance with all covenants under its bank credit facility, senior unsecured notes issued under the master shelf agreement and senior unsecured notes not subject to the master shelf agreement, refer to note 12 of the financial statements. Total debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment (EBITDA) and total senior debt to EBITDA was 2.66 times compared to the covenant of 3.5 times and total debt to capitalization was 0.34 times compared to the covenant of 0.5 times.

For 2018, Bonavista remains focused on creating incremental financial flexibility by allocating between 30% and 40% of adjusted funds flow to total debt repayment and the remainder to a moderate capital program. This capital program will be disciplined and focused on liquids rich locations within Bonavista's core areas and is budgeted to be between $135 million and $155 million, which will generate production between 69,000 and 71,000 boe per day. The payout ratio for 2018 is targeted to be between 60% and 70% with excess adjusted funds flow of between $60 million and $80 million used to reduce Bonavista's total debt.

***Shareholders' equity* -** As at December 31, 2017, Bonavista had 256.4 million equivalent common shares outstanding. This includes 3.2 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect at December 31, 2017 for exchangeable shares was 1.44650:1. As at March 1, 2018, Bonavista had 256.9 million equivalent common shares outstanding. This includes 3.2 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect at March 1, 2018 for exchangeable shares was 1.45293:1. In addition, Bonavista has 52,600 stock options as at March 1, 2018, with an average exercise price of $15.76 per common share and 5.3 million restricted incentive awards and 5.0 million performance incentive awards outstanding.

Dividends **-** For the year ended December 31, 2017, Bonavista declared dividends of $10.0 million ($0.04 per share) compared to $13.9 million ($0.06 per share) for the same period of 2016. For the three months ended December 31, 2017, Bonavista declared dividends of $2.5 million ($0.01 per share) compared to $2.5 million ($0.01 per share) for the same period of 2016. Bonavista announces and confirms its dividend policy 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.

Annual financial information **-** The following table highlights selected annual financial information for each of the three years ended December 31, 2017, 2016 and 2015.

Years ended December 31	**2017**	2016	2015
($ thousands, except per share amounts)			
Consolidated Statement of Loss and Comprehensive Loss Information			
Production revenues, net of royalties	**511,325**	408,531	545,798
Adjusted funds flow(1)	**301,988**	264,391	385,351
per share - basic	**1.18**	1.11	1.77
per share - diluted	**1.15**	1.09	1.75
Net loss	**(27,930)**	(95,998)	(751,545)
per share - basic	**(0.11)**	(0.40)	(3.45)
per share - diluted	**(0.11)**	(0.40)	(3.45)
Consolidated Statement of Financial Position Information			
Net capital expenditures	**281,745**	(13,430)	284,556
Total assets	**2,959,470**	3,172,157	3,523,716
Working capital deficiency(2)	**(13,279)**	(150,112)	(16,230)
Long-term debt	**800,544**	775,887	1,231,031
Shareholders' equity	**1,539,461**	1,560,244	1,548,266
Dividends declared	**10,040**	13,891	76,762

(1) Adjusted funds flow 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.

(2) Working capital deficiency as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measure for other entities. Working capital deficiency excludes decommissioning liabilities.

Quarterly financial information **-** The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2016 to December 31, 2017:

	2017				**2016**			
	December 31	September 30	June 30	March 31	December 31	September 30	June 30	March 31
($ thousands, except per share amounts)								
Production revenues	147,188	121,901	140,731	143,182	141,842	108,206	90,908	104,478
Net income (loss)	(159,149)	(1,699)	44,490	88,428	(12,021)	(29,386)	(101,012)	46,421
Basic	(0.62)	(0.01)	0.17	0.35	(0.05)	(0.11)	(0.45)	0.21
Diluted	(0.62)	(0.01)	0.17	0.34	(0.05)	(0.11)	(0.45)	0.21

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 production volumes, 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 disposition of property, plant and equipment, gains and loss on the disposition of exploration and evaluations assets and impairment charges.

Disclosure controls and procedures **-** Disclosure controls and procedures have been designed to ensure that information to be disclosed by Bonavista is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures, as defined by National Instrument 52-109 Certification, to provide reasonable assurance that (i) material information relating to the Corporation is made known to the Corporation's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. All control systems by their nature have inherent limitations and, therefore, the Corporation's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal control over financial reporting **-** The Corporation’s Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined by National Instrument 51-109. Internal controls over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. 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. There were no changes made to Bonavista’s internal controls over financial reporting during the period beginning on January 1, 2017 and ending on December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Corporation’s internal controls over financial reporting. Management has concluded that Bonavista's internal control over financial reporting was effective as of December 31, 2017. This assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Future accounting policies **-** Below is a description of new IFRS standards that are not yet effective and have not been applied in the preparation of these financial statements. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material impact on the Corporation's financial statements.

- In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. Bonavista will adopt IFRS 15 on a retrospective basis on January 1, 2018. Bonavista has completed the initial review of its various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on Bonavista's net income and financial position. The adoption of IFRS 15 will however require expanded disclosures including the disaggregation of revenue by product type.
- In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bonavista will adopt IFRS 9 on a retrospective basis on January 1, 2018. Bonavista has determined that there will not be any material changes to the measurement and carrying values of the Corporation's financial instruments as a result of the adoption of IFRS 9. Bonavista does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument commodity contracts upon adoption of IFRS 9 and is finalizing its assessment as to whether hedge accounting will be adopted for financial instrument contracts upon adoption of IFRS 9. IFRS 9, as well as consequential amendments to IFRS 7 *Financial Instruments: Disclosures,* will be applied on a retrospective basis by Bonavista on January 1, 2018.
- 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 would require 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. Early adoption is permitted for entities that apply IFRS 15 *Revenue from Contracts with Customers* at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. Bonavista is currently in the process of identifying, gathering and analyzing contracts that fall into the scope of the new standard. The extent of the impact of the adoption of the standard has not yet been determined.

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 3 of the Notes to the Financial Statements. The timely preparation of Bonavista's financial statements requires management to make certain judgments, estimates and assumptions. These estimates and judgments are subject to changes and actual results could differ from those estimated. Significant judgments and estimates made by management in the preparation of the financial statements are outlined below.

- *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 January 1, 2017, the Corporation re-aligned certain cash-generating units with its current asset base on the basis of materiality as a result of ongoing divestiture activity. During the comparative year, Bonavista disposed of all of the assets in its Southern Alberta CGU.

- *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, 2017, 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 in both its Central Alberta CGU and British Columbia CGU and conducted an impairment test on each which evaluated the net present values. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

- *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.

- *Depreciation, depletion and amortization* - 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 plus probable reserves.

- *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.

- *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.

Non-GAAP Measures - Throughout Bonavista's MD&A and Message to Shareholders, 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.

Management uses the following terms to analyze operating performance on a comparable basis with prior periods. "Operating netbacks" is equal to production revenues and realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation expenses calculated on a per boe basis. "Operating margin" is equal to production revenues and realized gains and losses on financial instrument commodity contracts less royalties, operating costs and transportation costs; 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 netback and operating margin metrics. "Cash costs" is equal to the total of operating, transportation, general and administrative, and financing expenses calculated on a per boe basis. "Total boe equivalent" is calculated by multiplying the daily production by the number of days in the period. "Adjusted funds flow per share" is equal to adjusted funds flow (described below in Additional Operational Measures) based on the number of shares outstanding consistent with the calculation of net income (loss) per share.

Additional Operational Measures - In addition to the Non-GAAP Measures described above, there are also terms that have been reconciled in Bonavista's financial statements to their most comparable IFRS measures. These terms do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. These terms have been referenced in Bonavista's Annual Report. These terms are used by Bonavista's management to analyze operating performance on a comparable basis with prior periods and to analyze the liquidity of the Corporation.

"Adjusted funds flow" is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with IFRS. All references to adjusted funds flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures and interest expense. "Total net debt" is equal to the long-term portion of Bonavista's bank debt and senior unsecured notes, net of adjusted working capital deficiency. "Adjusted working capital deficiency" excludes the current assets and liabilities from financial instrument commodity contracts and decommissioning liabilities. "Total net debt to adjusted funds flow" is equal to total net debt divided by adjusted funds flow for the relevant period. "Annualized current quarter adjusted funds flow" is equal to the identified quarters adjusted funds flow annualized for the year.

Oil and Gas Advisories - In Bonavista's Annual Report management also makes reference 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" 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 also be made to Bonavista's Annual Information Form. Finding and development 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 development and exploration activities in the year by the change in reserves from the prior year for the reserve category. Finding, development and acquisition 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 development and exploration 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 (refer to Non-GAAP Measures) for the period by the F&D costs per boe for the particular reserve category. FD&A recycle ratio is calculated by dividing the operating netback (refer to Non-GAAP Measures) for the period by the FD&A costs per boe for the particular reserve category. 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.

The Annual Report also refers to payout which has been prepared by management and is used to measure performance. This term does not have standardized meaning or standard calculation and is not comparable to similar measures used by other entities. The Annual Report also refers to 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 twelve month production rate.

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 Statements - This Annual Report contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words “anticipate”, “except”, “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 Annual Report, 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 pertaining to the following:

- Forecasted capital expenditures for 2018 including drilling, exploration and development plans, acquisition and disposition activities and expected future drilling locations;
- Expected development economics for certain properties in 2018;
- Expected 2018 total average production volumes and anticipated product mix;
- Expected 2018 oil, gas and natural gas liquids production volumes;
- Expected realized oil, gas and natural gas liquids prices and the differentials resulting from our financial risk management program in 2018;
- The benefits of Bonavista's hedging portfolio;
- Expected 2018 adjusted funds flow;
- Anticipated rate of return and future payout ratio;
- Expected exit 2018 net debt to adjusted funds flow; and
- The objective to manage net debt to adjusted funds flow to be well positioned to create shareholder value and organic growth.

References to 2018 drilling locations and future drilling locations do not provide certainty that Bonavista will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling locations on which Bonavista actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of our other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves or production. In addition, references made in the Annual Report to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Bonavista. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, Bonavista cautions that the test results should be considered to be preliminary.

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, 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.

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

March 1, 2018
Calgary, Alberta

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bonavista Energy Corporation

We have audited the accompanying consolidated financial statements of Bonavista Energy Corporation, which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

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

KPMG LLP

Chartered Professional Accountants

March 1, 2018

Calgary, Canada

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Financial Position

As at December 31	Note	2017	2016
($ thousands)			
Assets			
Current assets			
Cash		—	85,977
Accounts receivable		73,451	67,572
Prepaid expenses and other assets		14,680	17,054
Financial instrument commodity contracts	(5)	64,496	5,361
Financial instrument contracts	(5)	—	2,488
		152,627	178,452
Financial instrument commodity contracts	(5)	10,260	3,030
Financial instrument contracts	(5)	—	2,343
Property, plant and equipment	(9)	2,658,352	2,843,763
Exploration and evaluation assets	(10)	138,231	144,569
Total assets		2,959,470	3,172,157
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities		125,242	117,900
Current portion of long-term debt	(12)	—	154,334
Current portion of decommissioning liabilities	(13)	16,146	20,936
Dividends payable		2,518	2,493
Financial instrument commodity contracts	(5)	38,146	53,837
		182,052	349,500
Financial instrument commodity contracts	(5)	10,423	35,981
Financial instrument contracts	(5)	19,295	469
Long-term debt	(12)	800,544	775,887
Other long-term liabilities		6,603	8,816
Decommissioning liabilities	(13)	393,180	416,986
Deferred income taxes	(14)	7,912	24,274
Total liabilities		1,420,009	1,611,913
Shareholders' equity	(11)		
Shareholders' capital		2,852,643	2,837,945
Exchangeable shares		93,266	93,859
Contributed surplus		56,531	53,449
Deficit		(1,462,979)	(1,425,009)
Total shareholders' equity		1,539,461	1,560,244
Total liabilities and shareholders' equity		2,959,470	3,172,157

Commitments (note 15) and Subsequent events (note 5)

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 Loss and Comprehensive Loss

For the years ended December 31	Note	2017	2016
($ thousands, except per share amounts)			
Revenues			
Production		**553,002**	445,434
Royalties		**(41,677)**	(36,903)
Production revenues, net of royalties		**511,325**	408,531
Realized gains on financial instrument commodity contracts	(5)	**25,566**	91,772
Unrealized gains (losses) on financial instrument commodity contracts	(5)	**107,614**	(161,930)
Production revenues, net of royalties and financial instrument commodity contracts		**644,505**	338,373
Expenses			
Operating		**147,165**	140,592
Transportation		**24,871**	22,566
General and administrative		**24,749**	27,138
Share-based compensation	(11)	**15,702**	8,994
Gain on disposition of property, plant and equipment	(9)	**(13,589)**	(66,354)
Gain on disposition of exploration and evaluation assets	(9)	**(976)**	(23,738)
Depletion, depreciation, amortization and impairment	(9)	**469,555**	319,845
Total expenses		**667,477**	429,043
Loss from operating activities		**(22,972)**	(90,670)
Finance costs	(7)	**104,938**	128,717
Finance income	(7)	**(83,729)**	(84,460)
Net finance costs		**21,209**	44,257
Loss before taxes		**(44,181)**	(134,927)
Deferred income tax recovery	(14)	**(16,251)**	(38,929)
Net loss and comprehensive loss		**(27,930)**	(95,998)
Net loss and comprehensive loss per share			
Basic	(11)	**(0.11)**	(0.40)
Diluted	(11)	**(0.11)**	(0.40)

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Changes in Equity

For the years ended December 31	Shareholders' Capital	Exchangeable Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
($ thousands)					
Balance as at December 31, 2015	2,716,011	94,550	52,825	(1,315,120)	1,548,266
Net loss and comprehensive loss	—	—	—	(95,998)	(95,998)
Issuance of equity	115,001	—	—	—	115,001
Issue costs, net of deferred tax benefit	(3,630)	—	—	—	(3,630)
Conversion of restricted incentive and performance incentive awards	9,200	—	(9,200)	—	—
Tax effect on conversion of restricted incentive and performance incentive awards	672	—	—	—	672
Share-based compensation expense	—	—	8,994	—	8,994
Share-based compensation capitalized	—	—	830	—	830
Exchangeable shares exchanged for common shares	691	(691)	—	—	—
Dividends declared	—	—	—	(13,891)	(13,891)
Balance as at December 31, 2016	2,837,945	93,859	53,449	(1,425,009)	1,560,244
Net loss and comprehensive 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**

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Cash Flows

For the years ended December 31	**Note**	**2017**	2016
($ thousands)			
Cash provided by (used in):			
Operating Activities			
Net loss and comprehensive loss		**(27,930)**	(95,998)
Adjustments for:			
Depletion, depreciation, amortization and impairment		**469,555**	319,845
Share-based compensation		**15,702**	8,994
Unrealized losses (gains) on financial instrument commodity contracts		**(107,614)**	161,930
Gain on disposition of property, plant and equipment		**(13,589)**	(66,354)
Gain on disposition of exploration and evaluation assets		**(976)**	(23,738)
Net finance costs		**21,209**	44,257
Deferred income tax recovery		**(16,251)**	(38,929)
Decommissioning expenditures		**(17,318)**	(15,309)
Changes in non-cash working capital items	(8)	**2,831**	(33,906)
Cash flow from operating activities		**325,619**	260,792
Financing Activities			
Issuance of equity, net of issue costs		**—**	110,032
Dividends paid		**(10,015)**	(13,538)
Interest paid		**(39,344)**	(45,770)
Net repayment of long-term debt		**(79,464)**	(258,035)
Cash flow used in financing activities		**(128,823)**	(207,311)
Investing Activities			
Exploration and development		**(289,029)**	(153,871)
Property acquisitions		**(13,736)**	(12,166)
Property dispositions		**21,577**	180,071
Office equipment		**(557)**	(604)
Changes in non-cash working capital items	(8)	**(1,028)**	19,066
Cash flow from (used in) investing activities		**(282,773)**	32,496
Change in cash		**(85,977)**	85,977
Cash, beginning of year		**85,977**	—
Cash, end of year		**—**	85,977

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 oil and natural gas 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, 2017, are available through our filings 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 3. These accounting policies have been applied consistently for all periods presented in these financial statements.

These financial statements were authorized for issue by the Corporation's Board of Directors on March 1, 2018.

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 January 1, 2017, the Corporation re-aligned certain cash-generating units with its current asset base on the basis of materiality as a result of ongoing divestiture activity. During the comparative year, Bonavista disposed of all of the assets in its Southern Alberta 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, 2017, 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 in both its Central Alberta CGU and British Columbia CGU and conducted an impairment test on each which evaluated the net present values (note 9). 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.

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 plus 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. Significant accounting policies

Basis of consolidation

The consolidated financial statements comprise the financial statements of Bonavista and its subsidiaries as at December 31, 2017. 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

i. Non-derivative financial assets

Bonavista initially recognizes loans, receivables and deposits on the date that they are 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.

The Corporation 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.

Financial assets and liabilities are offset and the net amount is presented in the statement of consolidated 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.

Bonavista classifies non-derivative financial assets into the following categories: financial assets at fair value through profit or loss, held-to-maturity financial assets, loans and receivables and available-for-sale financial assets.

Financial assets at fair value through profit or loss

A financial asset is classified at fair value through profit or loss if it is classified as held for trading or is designated as such upon initial recognition. Financial assets are designated at fair value through profit or loss if Bonavista manages such investments and makes purchase and sale decisions based on their fair value in accordance with Bonavista's documented risk management or investment strategy. Attributable transaction costs are recognized in profit or loss as incurred.

Financial assets at fair value through profit or loss are measured at fair value and changes therein are recognized in the consolidated statement of income (loss).

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Loans and receivables comprise of cash and cash equivalents, and trade and other receivables.

Cash and cash equivalents

Cash and cash equivalents comprise cash balances and call deposits with original maturities of three months or less.

ii. Non-derivative financial liabilities

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

Bonavista derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Bonavista classifies non-derivative financial liabilities into the other financial liabilities category. Such financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest method.

Other financial liabilities comprise loans and borrowings, bank overdrafts, and trade and other payables. Bank overdrafts that are repayable on demand and form an integral part of Bonavista's cash management are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

iii. Derivative financial instruments

Bonavista has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange rates. These instruments are not used for trading or speculative purposes. Bonavista has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Corporation considers all commodity contracts and foreign exchange contracts to be economic hedges. Derivatives are recognized initially at fair value and any attributable transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are recognized immediately in profit or loss.

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 oil and natural gas revenues.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in the consolidated statement of income (loss).

iv. Shareholders’ capital and Exchangeable shares

Common shares and exchangeable shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

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

i. Non-derivative financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in the consolidated statement of income (loss).

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the consolidated statement of income (loss).

ii. Non-financial financial assets

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. 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 stock option, restricted incentive award and performance incentive award plans.

The fair value of stock options is assessed on the grant date using the Black-Scholes option pricing model. The fair value is subsequently recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon exercise of the options, consideration paid by the stock option holders and the value in contributed surplus pertaining to the exercised options is recorded as shareholders' capital.

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 share 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.

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 share awards by common shares, on the predetermined payment date, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

Under the long-term incentive plans, forfeiture rates are assigned in the determination of fair value. 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

Revenues from the sale of oil, natural gas liquids and natural gas are recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. Revenues are measured net of discounts, customs, duties and royalties. With respect to the latter, the Corporation is acting as a collection agent on behalf of others. Revenue is measured at the fair value of the consideration received or receivable.

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 the profit or 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 the profit or 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.

4. Future accounting policies

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. Bonavista will adopt IFRS 15 on a retrospective basis on January 1, 2018. Bonavista has completed the initial review of its various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on Bonavista's net income and financial position. The adoption of IFRS 15 will however require expanded disclosures including the disaggregation of revenue by product type.

In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bonavista will adopt IFRS 9 on a retrospective basis on January 1, 2018. Bonavista has determined that there will not be any material changes to the measurement and carrying values of the Corporation's financial instruments as a result of the adoption of IFRS 9. Bonavista does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument commodity contracts upon adoption of IFRS 9 and is finalizing its assessment as to whether hedge accounting will be adopted for financial instrument contracts upon adoption of IFRS 9. IFRS 9, as well as consequential amendments to IFRS 7 *Financial Instruments: Disclosures,* will be applied on a retrospective basis by Bonavista on January 1, 2018.

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 would require 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. Early adoption is permitted for entities that apply IFRS 15 *Revenue from Contracts with Customers* at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. Bonavista is currently in the process of identifying, gathering and analyzing contracts that fall into the scope of the new standard. The extent of the impact of the adoption of the standard has not yet been determined.

5. 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 (note 6).

Commodity price risk

Bonavista is exposed to commodity price risk as prices received for its oil, natural gas liquids and natural gas 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, 2017, Bonavista had entered into the following costless collars to sell oil and natural gas:

Volume		Average Price	Contract	Term
Natural gas contracts				
5,000	gjs/d	CDN $2.90 - CDN $3.10	AECO - Costless Collar	January 1, 2018 - March 31, 2018
20,000	gjs/d	CDN $2.60 - CDN $3.00	AECO - Costless Collar	January 1, 2018 - December 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10	AECO - Costless Collar	November 1, 2018 - March 31, 2019
Oil contract				
250	bbls/d	CDN $65.00 - CDN $ 70.02	WTI - Costless Collar	January 1, 2019 - December 31, 2020

At December 31, 2017, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas contracts				
45,000	gjs/d	CDN $3.08	AECO - Swap	January 1, 2018 - March 31, 2018
40,000	gjs/d	CDN $2.88	AECO - Swap	January 1, 2018 - December 31, 2018(1)(4)
10,000	gjs/d	CDN $2.69	AECO - Swap	January 1, 2018 - March 31, 2019
24,000	gjs/d	CDN $2.20	AECO - Swap	April 1, 2018 - October 1, 2018
20,000	gjs/d	CDN $2.68	AECO - Swap	April 1, 2018 - December 31, 2018
10,000	gjs/d	CDN $2.70	AECO - Swap	April 1, 2018 - December 31, 2019
5,000	gjs/d	CDN $3.05	AECO - Swap	November 1, 2018 - March 31, 2019
20,000	mmbtu/d	US ($0.68)	AECO - Basis Swap	January 1, 2018 - December 31, 2018
23,695	mmbtu/d	US ($1.25)	AECO - Basis Swap	April 1, 2018 - October 31, 2018
10,000	mmbtu/d	US ($0.98)	AECO - Basis Swap	January 1, 2019 - December 31, 2021
10,000	mmbtu/d	US ($0.16)	DAWN - Basis Swap	January 1, 2018 - December 31, 2018
20,000	mmbtu/d	US $2.97	NYMEX - Swap	January 1, 2018 - December 31, 2018
5,000	mmbtu/d	US $2.70	NYMEX - Swap	April 1, 2018 - October 1, 2018
10,000	mmbtu/d	US $4.00	NYMEX - Sold Call	January 1, 2018 - December 31, 2018
10,000	mmbtu/d	US $3.75	NYMEX - Sold Call	January 1, 2019 - December 31, 2021
Natural gas liquids contracts				
500	bbls/d	US $31.50	MTB BT - Swap	January 1, 2018 - March 31, 2018(2)
1,000	bbls/d	US $28.77	MTB BT - Swap	January 1, 2018 - December 31, 2018(2)
500	bbls/d	US $32.76	MTB BT - Swap	January 1, 2018 - December 31, 2019(2)
500	bbls/d	US $29.40	MTB BT - Swap	April 1, 2018 - December 31, 2018(2)
1,000	bbls/d	US $32.13	MTB BT - Swap	January 1, 2019 - December 31, 2019(2)
750	bbls/d	US $34.86	MTB BT - Swap	January 1, 2019 - December 31, 2020(2)
1,000	bbls/d	US $23.04	CNWY PN - Swap	January 1, 2018 - March 31, 2018(3)
1,500	bbls/d	US $21.18	CNWY PN - Swap	January 1, 2018 - December 31, 2018(3)
1,000	bbls/d	US $25.25	CNWY PN - Swap	January 1, 2018 - December 31, 2019(3)
500	bbls/d	US $29.40	CNWY PN - Swap	April 1, 2018 - June 30, 2018(3)
500	bbls/d	US $22.05	CNWY PN - Swap	July 1, 2018 - December 31, 2018(3)
1,250	bbls/d	US $25.91	CNWY PN - Swap	January 1, 2019 - December 31, 2019(3)
250	bbls/d	US $29.40	CNWY PN - Swap	January 1, 2019 - December 31, 2020(3)
Oil contracts				
1,000	bbls/d	US $50.00	WTI - Swap	January 1, 2018 - December 31, 2018
1,500	bbls/d	CDN $70.17	WTI - Swap	January 1, 2018 - December 31, 2018
1,500	bbls/d	CDN $69.82	WTI - Swap	January 1, 2018 - December 31, 2019
1,000	bbls/d	CDN $70.25	WTI - Swap	January 1, 2019 - December 31, 2019
500	bbls/d	CDN $65.00	WTI - Sold Call	January 1, 2018 - December 31, 2018

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 30,000 gjs/d on the last trade date of each month for the duration of the contract.
(2) Mont Belvieu 65 nC4/35 iC4 price.
(3) Conway propane price.
(4) Includes an extendable feature on 10,000 gjs/d at $2.75 gjs/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2019.

Subsequent to December 31, 2017, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
10,000	mmbtu/d	US $2.73	NYMEX - Sold Call	March 1, 2018 - December 31, 2018
15,000	mmbtu/d	US $2.74	NYMEX - Swap	April 1, 2018 - October 31, 2018
10,000	mmbtu/d	US $2.91	NYMEX - Swap	January 1, 2019 - December 31, 2019
10,000	mmbtu/d	US ($1.00)	AECO - Basis Swap	January 1, 2019 - December 31, 2019
1,000	bbls/d	US $54.60	WTI - Sold Call	January 1, 2020 - December 31, 2020
250	bbls/d	US $24.78	CNWY PN - Swap	January 1, 2020 - December 31, 2020(1)

(1) Conway propane price.

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 loss and comprehensive loss at December 31, 2017:

	Change in AECO	
($ thousands)	Increase $0.10	Decrease $0.10
Natural Gas Commodity Contracts	(10,537)	10,475

	Change in WTI	
($ thousands)	Increase $1.00	Decrease $1.00
Oil Commodity Contracts	(2,096)	2,003

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 loss and comprehensive loss. At December 31, 2017, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $26.2 million (December 31, 2016 - $81.4 million, net liability) of which a net asset of $26.4 million (December 31, 2016 - $48.5 million, net liability) relates to financial instrument commodity contracts with term dates within one year and a net liability of $0.2 million (December 31, 2016 - $33.0 million, net liability) relates to financial instrument commodity contracts with term dates beyond one year. During the year ended December 31, 2017, a net gain of $133.2 million (December 31, 2016 - $70.2 million, net loss) was recorded on the consolidated statement of loss and comprehensive loss, consisting of a realized gain of $25.6 million (December 31, 2016 - $91.8 million realized gain) and an unrealized gain of $107.6 million (December 31, 2016 - $161.9 million unrealized loss).

Physical purchase and sale contracts

At December 31, 2017, Bonavista had entered into the following physical contracts to sell natural gas:

Volume		Price	Term
20,000	gjs/d	CDN $3.00	January 1, 2018 - December 31, 2018(1)
10,000	gjs/d	CDN $2.75	April 1, 2018 - October 31, 2018(2)

(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.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 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 oil, natural gas liquids and natural gas prices are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar oil, natural gas liquids and natural gas 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$/US$
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

Subsequent to December 31, 2017, Bonavista entered into the following contracts to mitigate the foreign exchange risk on its US dollar denominated interest obligations:

Settlement date	Contract	Notional US$	CDN$/US$
2018(1)	US$ purchased forward	$9,314,400	1.2288
2019(1)	US$ purchased forward	$9,314,400	1.2288

(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 in both 2018 and 2019.

The following table highlights the approximate impact that a change in the fair value of the financial instrument contracts would have on net loss and comprehensive loss at December 31, 2017:

	Change in CDN$/US$	
($ thousands)	Increase $0.01	Decrease $0.01
Financial Instrument Contracts	(4,718)	1,089

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. The fair value recorded on the consolidated statement of financial position for these financial instrument contracts as at December 31, 2016 was a net asset of $4.4 million of which $2.5 million relates to financial instrument contracts with term dates within one year and $1.9 million relates to financial instrument contracts with term dates beyond one year. For the year ended December 31, 2017, an unrealized loss of $23.7 million was recorded on the consolidated statement of loss and comprehensive loss (December 31, 2016 - $66.4 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, 2017 pertains to accrued sales revenue for December 2017 production volumes. Receivables from oil and natural gas marketers are normally collected by Bonavista on the 25th 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, 2017 Bonavista's receivables consisted of $63.3 million of receivables from oil and natural gas marketers of which substantially all has been collected subsequent to December 31, 2017 and $10.2 million from joint operations partners of which $3.6 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, 2017 Bonavista has $4.6 million in accounts receivable that is considered to be past due (December 31, 2016 - $1.7 million) of which $0.9 million has been subsequently collected. 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 carrying amount of accounts receivable and financial instrument contracts represents the maximum credit exposure. Bonavista does not have an allowance for doubtful accounts at December 31, 2017 (December 31, 2016 - nil) and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2017 (December 31, 2016 - nil).

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 12, 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 12, which range in maturities from November 2, 2020 to May 23, 2025. 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 fair value measurements classified as 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, 2017	December 31, 2016
($ thousands)		
Current assets		
Financial instrument commodity contracts(1)	**64,496**	5,361
Financial instrument contracts(1)	**—**	2,488
Long-term assets		
Financial instrument commodity contracts(1)	**10,260**	3,030
Financial instrument contracts(1)	**—**	2,343
Current liabilities		
Financial instrument commodity contracts(1)	**(38,146)**	(53,837)
Long-term liabilities		
Financial instrument commodity contracts(1)	**(10,423)**	(35,981)
Financial instrument contracts(1)	**(19,295)**	(469)
Net asset (liability)	**6,892**	(77,065)

(1) Level 2

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, 2017 was approximately $722.9 million (December 31, 2016 - $931.9 million), compared to a carrying amount of $730.4 million (December 31, 2016 - $933.0 million).

6. Capital Management

Bonavista's objectives when managing capital are to: (i) preserve financial flexibility which will allow it to execute on its growth 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 light oil, natural gas liquids and natural gas assets. This is accomplished by consistently aligning Bonavista's capital and dividend programs with adjusted funds flow.

Bonavista considers its capital structure to include adjusted 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 annualized adjusted funds flow. The ratio represents the time period it would take to pay off the net debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio is calculated as net debt, defined as outstanding bank debt (excluding outstanding letters of credit), senior unsecured notes and adjusted working capital, 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. As at December 31, 2017, Bonavista's ratio of net debt to fourth quarter annualized adjusted funds flow was 2.4 to 1 (December 31, 2016 - 2.8 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 oil, natural gas liquids and natural gas 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; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its 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 that are outlined in note 12 of the financial statements.

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

	Three months ended December 31,		Years ended December 31,	
Calculation of Adjusted Funds Flow	**2017**	2016	**2017**	2016
($ thousands)				
Cash flow from operating activities	**94,515**	70,761	**325,619**	260,792
Interest expense(1)	**(8,953)**	(10,856)	**(38,118)**	(45,616)
Decommissioning expenditures	**5,746**	6,637	**17,318**	15,309
Changes in non-cash working capital	**(5,200)**	12,200	**(2,831)**	33,906
Adjusted funds flow(2)	**86,108**	78,742	**301,988**	264,391

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issue costs.

(2) Adjusted funds flow 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.

The following table represents Bonavista's ratio of net debt to adjusted funds flow:

Net Debt to Adjusted Funds Flow	**Year ended December 31, 2017**	Year ended December 31, 2016
($ thousands)		
Long Term Debt	**800,544**	775,887
Adjusted working capital deficiency(1)	**39,629**	101,636
Total net debt(2)	**840,173**	877,523
Adjusted funds flow fourth quarter annualized	**344,432**	314,968
Total net debt to adjusted funds flow	**2.4:1**	2.8:1
Adjusted funds flow	**301,988**	264,391
Total net debt to adjusted funds flow	**2.8:1**	3.3:1

(1) Adjusted working capital deficiency as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Adjusted working capital deficiency excludes associated assets or liabilities for financial instrument commodity contracts and decommissioning liabilities.
(2) Total net debt as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures with other entities. Total net debt excludes outstanding letters of credit on Bonavista's bank credit facility.

7. Finance costs and income

	Year ended December 31, 2017	Year ended December 31, 2016
($ thousands)		
Finance costs		
Accretion of decommissioning liabilities	**8,581**	8,251
Accretion of other liabilities	**1,066**	1,258
Interest on bank debt	**2,959**	9,309
Interest on notes payable	**36,000**	37,901
Realized loss on foreign exchange	**32,675**	5,491
Unrealized loss on marketable securities	**—**	102
Unrealized loss on financial instrument contracts	**23,657**	66,405
Total finance costs	**104,938**	128,717
Finance income		
Realized gain on financial instrument contracts	**—**	(48,089)
Unrealized gain on foreign exchange	**(83,729)**	(36,371)
Total finance income	**(83,729)**	(84,460)
Net finance costs	**21,209**	44,257

8. Supplemental cash flow information

	Year ended December 31, 2017	Year ended December 31, 2016
($ thousands)		
Cash provided by (used for):		
Accounts receivable	**(5,879)**	2,706
Prepaid expenses and other assets	**2,393**	5,306
Accounts payable and accrued liabilities, net of interest accrual	**5,289**	(22,852)
	1,803	(14,840)
Related to:		
Operating activities	**2,831**	(33,906)
Investing activities	**(1,028)**	19,066
	1,803	(14,840)

9. Property, plant and equipment

Cost	Oil and natural gas properties	Facilities	Other Assets	Total
($ thousands)				
Balance as at December 31, 2015	5,255,022	558,674	28,779	5,842,475
Additions	152,294	4,377	604	157,275
Acquisitions	115,670	40,053	—	155,723
Transfers from exploration and evaluation assets	25,868	—	—	25,868
Changes in decommissioning liabilities	13,958	—	—	13,958
Dispositions	(662,440)	(76,848)	—	(739,288)
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**
Depletion, depreciation, amortization and impairment				
Balance as at December 31, 2015	(2,642,751)	(119,832)	(15,557)	(2,778,140)
Depletion, depreciation, amortization and impairment	(294,015)	(23,291)	(2,539)	(319,845)
Dispositions	462,450	23,287	—	485,737
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)**
Carrying amount				
As at December 31, 2017	**2,251,641**	**397,041**	**9,670**	**2,658,352**
As at December 31, 2016	2,426,056	406,420	11,287	2,843,763

For the year ended December 31, 2017, $5.6 million (December 31, 2016 - $4.7 million) of direct general and administrative expenses were capitalized. At December 31, 2017, future development costs of $1,415.0 million were included in Bonavista's depletion calculation (December 31, 2016 - $1,320.0 million).

During the year ended December 31, 2017, Bonavista successfully disposed of certain non-core petroleum and natural gas rights, through asset exchanges and other property dispositions 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.

During the comparative year ended December 31, 2016, cash proceeds from non-core dispositions totaled $180.1 million, resulting in a before tax gain on sale of property plant and equipment of $34.3 million and a before tax loss on exploration and evaluation assets of $1.9 million. In the fourth quarter of 2016, Bonavista also completed an asset exchange whereby certain properties and petroleum and natural gas rights were acquired within the Deep Basin and West Central core areas in exchange for non-core assets in the Blueberry area of northeast British Columbia. The carrying value of the Blueberry assets disposed was $83.9 million and the fair value of the core area assets acquired was $141.6 million, resulting in a gain on the exchange of $57.7 million.

Impairment Assessment

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 technical reserve revisions. As such impairment tests were carried out on both the Central Alberta CGU and British Columbia CGU resulting in a total property, plant and equipment ("PP&E") impairment of $215.0 million. The recoverable amount of each CGU tested for impairment at December 31, 2017 was determined using the methodology and assumptions noted below.

Impairments were recorded in the following CGUs for the year ended December 31, 2017:

- British Columbia CGU, located mainly in northeast British Columbia near Fort St. John, composed of primarily natural gas and natural gas liquids producing assets, recorded a $28.0 million (December 31, 2016 - nil) PP&E impairment. The estimated recoverable amount of the British Columbia CGU as at December 31, 2017 was $22.3 million. The recoverable amount was determined using the fair value less costs of disposal methodology.
- Central Alberta CGU, composed of primarily natural gas and natural gas liquids producing assets, recorded a $187.0 million (December 31, 2016 - nil) PP&E impairment. The estimated recoverable amount of the Central Alberta CGU as at December 31, 2017 was $1,047.9 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, 2017 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 used ranged from eight to 15 percent. 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. In the impairment tests conducted, management also independently considered an estimated value of its integrated infrastructure systems and physical diversification contracts.

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 additional impairment charges or recovery of impairment charges. If the before-tax discount rates used in the determination of the recoverable amounts for the British Columbia CGU and Central Alberta CGU had decreased by two percent, the impairment charge for the year ended December 31, 2017, would have been reduced by $177.0 million to $38.0 million. Similarly, if a before-tax discount rate used in the determination of the recoverable amounts for the British Columbia CGU and Central Alberta CGU had increased by two percent, Bonavista would have recorded an additional impairment charge of $117.0 million for the year ended December 31, 2017. The impairments recorded for the year ended December 31, 2017 may be reversed at such time that the recoverable value of the impaired CGU increases.

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.

At December 31, 2016, Bonavista evaluated its property, plant and equipment ("PP&E") assets for indicators of any potential impairment or related reversal. No indicators of impairment were identified as a result of this assessment and as such no impairment test was performed on Bonavista's PP&E assets at December 31, 2016. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

At June 30, 2016, Bonavista had classified certain non-core properties in its Southern Alberta CGU as assets held for sale, as a result, an impairment charge of $56.6 million was recorded using the fair value less costs of disposal methodology based on the estimated consideration to be received according to the purchase and sale agreement. These Southern Alberta assets were disposed of on July 12, 2016. As a result of this disposition, Bonavista disposed of its Southern Alberta CGU in its entirety.

10. Exploration and evaluation ("E&E") assets

Carrying amount	
($ thousands)	
Balance as at December 31, 2015	210,194
Additions	2,840
Acquisitions	10,562
Dispositions	(53,159)
Transfers to property, plant and equipment	(25,868)
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**

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 2017 and 2016 represent Bonavista's share of costs incurred on E&E assets during the year.

Impairment Assessment

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. For the purpose of impairment testing, the recoverable amounts of E&E assets were determined using internal estimates of the fair value of undeveloped land and seismic assets based principally on recent and relevant land sales. 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.

At December 31, 2016, Bonavista determined that no indicators of potential impairment existed with respect to its E&E assets; therefore an impairment test was not performed.

11. 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, 2017 were $0.04 per share (December 31, 2016 - $0.06 per share). Bonavista announces its dividend policy and confirms its dividend payment on a quarterly basis.

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 times the exchange ratio for each exchangeable share.

a. Issued and outstanding

Common shares

	Common Shares	Amount
	(thousands)	($ thousands)
Balance as at December 31, 2015	213,979	2,716,011
Issued for cash	34,328	115,001
Issue costs, net of deferred tax benefit	—	(3,630)
Issued on conversion of exchangeable shares	34	691
Conversion of restricted incentive and performance incentive awards, including tax effect	936	672
Share-based compensation	—	9,200
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, including tax effect	**2,440**	**111**
Share-based compensation	**—**	**13,994**
Balance as at December 31, 2017	**251,747**	**2,852,643**

Exchangeable shares

	Year ended December 31, 2017		Year ended December 31, 2016	
	Exchangeable Shares	**Amount**	Exchangeable Shares	Amount
	(thousands)	($ thousands)	(thousands)	($ thousands)
Balance, beginning of year	3,259	93,859	3,283	94,550
Exchanged for common shares	**(21)**	**(593)**	(24)	(691)
Balance, end of year	**3,238**	**93,266**	3,259	93,859
Exchange ratio, end of year	1.44650	—	1.42923	—
Common shares issuable on exchange	**4,684**	**93,266**	4,658	93,859

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, 2017, the number of shares issuable under Bonavista's long-term incentive plans, in aggregate represented 2.6% of issued and outstanding common shares including common shares issuable on the exchange of outstanding exchangeable shares.

Share-based compensation expense recognized during the year ended December 31, 2017 was $15.7 million (December 31, 2016 - $9.0 million). For the year ended December 31, 2017, $1.4 million of share-based compensation expense was capitalized to property, plant and equipment (December 31, 2016 - $0.8 million). As at December 31, 2017, the balance of contributed surplus attributable to share-based compensation awards was $56.5 million (December 31, 2016 - $53.4 million).

Stock option plan

Bonavista did not grant any awards under the stock option plan during the years ended December 31, 2017 and December 31, 2016. At December 31, 2017 there were 65,400 stock options outstanding (December 31, 2016 - 101,468) all of which were exercisable (December 31, 2016 - 85,468).

The following table summarizes information regarding stock options outstanding at December 31, 2017:

	Outstanding			Exercisable	
Range of exercise prices	**Number outstanding**	**Weighted average remaining contractual life (years)**	**Weighted average exercise price**	**Number exercisable**	**Weighted average exercise price**
($ per share)			($ per share)		($ per share)
13.80 - 15.76	21,600	0.80	14.18	21,600	14.18
15.77 - 16.41	9,000	1.50	16.30	9,000	16.30
16.42 - 26.07	34,800	1.07	18.47	34,800	18.47
13.80 - 26.07	65,400	1.04	16.75	65,400	16.75

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. Bonavista's Board of Directors has approved an amended vesting arrangement of three tranches vesting evenly, over six, 18 and 30 month periods from the date of grant for those awards granted on January 1 of each related compensation year. 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 the 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 the restricted incentive awards granted during the year ended December 31, 2017 was $4.80 per award (December 31, 2016 - $2.60 per award). This 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 and Restricted Share Awards
Balance as at December 31, 2015	2,059,090
Granted	2,017,237
Reinvestment(1)	70,356
Vested	(883,006)
Forfeited	(320,500)
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**

(1) Reinvestment of dividends earned during the period outstanding.
(2) Weighted average trading price of the five 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 the 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 0.9992 and 1.1033 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 20 percent for outstanding the performance incentive awards. The estimated weighted average fair value of the performance incentive awards granted during the year ended December 31, 2017 was $4.88 per award (December 31, 2016 - $1.87).

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

	Performance Incentive Awards
Balance as at December 31, 2015	893,923
Granted	1,315,219
Reinvestment(1)	47,660
Vested	(53,258)
Forfeited	(322,025)
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**

(1) Reinvestment of dividends earned during the period outstanding.
(2) Weighted average trading price of the five 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 loss and comprehensive loss per equivalent share:

	Year ended December 31, 2017	Year ended December 31, 2016
(thousands)		
Common shares	**250,850**	233,130
Exchangeable shares converted at the exchange ratio	**4,709**	4,676
Basic equivalent shares	**255,559**	237,806
Restricted incentive and share awards	**3,116**	2,433
Performance incentive awards	**3,371**	1,867
Diluted equivalent shares	**262,046**	242,106

12. Long-term debt

	December 31, 2017	December 31, 2016
($ thousands)		
Bank credit facility[1]	**71,549**	—
Senior unsecured notes[1]	**728,995**	930,221
Total long-term debt	**800,544**	930,221
Current portion of long-term debt	**—**	154,334
Long-term portion of long-term debt	**800,544**	775,887

(1) Includes debt issue costs calculated using the effective interest rate method, of which $1.4 million pertains to the bank credit facility and $1.4 million pertains to senior unsecured notes.

a. Bank credit facility

On September 8, 2017, Bonavista elected to reduce the committed amount of its bank credit facility, provided by a syndicate of eight domestic banks, by $100 million from $600 million to $500 million. 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, 2017, borrowing costs averaged 3.6% (December 31, 2016 - 3.2%).

At December 31, 2017, Bonavista had $72.9 million drawn (December 31, 2016 - nil) on its bank credit facility and outstanding letters of credit of $18.0 million (December 31, 2016 - $8.1 million), which reduce the available borrowing capacity on its bank credit facility. For the years ended December 31, 2017 and December 31, 2016, Bonavista had no amounts drawn on its demand working capital facility.

Under the terms of the bank credit facility, Bonavista has provided the covenant that its: (i) 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; (ii) consolidated total debt will not exceed three and one half times of consolidated net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholder’s 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, 2017, including the Corporation'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, 2017, Bonavista was in compliance with all covenants under its bank credit 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. Under the terms of the master shelf agreement, Bonavista has provided similar significant covenants that exist under the bank credit facility.

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

Bonavista issued the following senior unsecured notes by way of a private placement. Under the terms of the senior unsecured notes, Bonavista has provided similar significant covenants that exist under the bank credit facility.

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, 2017 and 2016. 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

At December 31, 2017, Bonavista was in compliance with all covenants under its senior unsecured notes issued under the master shelf agreement and senior unsecured notes not subject to the master shelf agreement.

13. 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 $409.3 million at December 31, 2017 (December 31, 2016 - $437.9 million), based on an estimated total future undiscounted liability of approximately $837.3 million (December 31, 2016 - $889.0 million). At December 31, 2017 management estimates expenditures required to settle the liability will be made over the next 52 years with the majority of payments being made in years 2047 to 2069. A risk-free rate of approximately 2.3% (December 31, 2016 - 2.3%) based on the Bank of Canada’s long-term risk-free bond rate and an inflation rate of 1.8% (December 31, 2016 - 1.8%) were used to calculate the present value of the decommissioning liability at December 31, 2017.

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

($ thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Balance, beginning of year	437,922	488,901
Accretion expense	**8,581**	8,251
Liabilities incurred	**5,642**	4,810
Liabilities acquired	**1,034**	12,483
Liabilities disposed	**(14,242)**	(75,172)
Liabilities settled	**(17,318)**	(15,309)
Revaluation of liabilities acquired(1)	**—**	26,166
Change in estimate(2)	**(12,293)**	(12,208)
Balance, end of year	**409,326**	437,922
Expected to be incurred within one year	**16,146**	20,936
Expected to be incurred beyond one year	**393,180**	416,986

(1) Relates to the revaluation of acquired decommissioning liabilities using a risk-free discount rate. At the date of acquisition the acquired decommissioning liabilities were recorded at fair value.

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

14. Deferred income taxes

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

($ thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Loss before taxes	**(44,181)**	(134,927)
Current statutory income tax rate[1]	**27.0%**	27.0%
Income tax recovery at current statutory rate	**(11,929)**	(36,430)
Non-deductible (taxable) portion of realized and unrealized foreign exchange	**(3,694)**	(1,694)
Change in unrecognized deferred tax asset	**(3,694)**	(1,694)
Non-deductible share-based compensation	**2,760**	454
Other	**306**	435
Deferred income tax recovery	**(16,251)**	(38,929)

(1) The tax rate consists of the combined federal and provincial statutory tax rates for Bonavista for the years ended December 31, 2017 and December 31, 2016.

($ thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Deferred income tax liabilities:		
Capital assets in excess of tax value	**318,160**	346,796
Financial instrument contracts	**7,063**	(21,961)
Debt issue costs	**730**	745
Deferred income tax assets:		
Decommissioning liabilities	**(110,395)**	(118,108)
Non-capital losses	**(201,841)**	(175,784)
Other liability	**(2,378)**	(2,897)
Issue costs	**(1,490)**	(2,165)
Share-based compensation	**(1,937)**	(2,352)
Deferred income tax liability	**7,912**	24,274

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

($ thousands)	Balance December 31, 2015 (Asset)/Liability	Recognized in profit and loss (Recovery)/Expense	Recognized in equity (Asset)/Liability	Balance December 31, 2016 (Asset)/Liability
Property, plant and equipment	289,927	56,869	—	346,796
Decommissioning liabilities	(131,759)	13,651	—	(118,108)
Non-capital losses	(109,515)	(66,269)	—	(175,784)
Issue costs	(2,499)	1,673	(1,339)	(2,165)
Other liability	(3,345)	448	—	(2,897)
Debt issue costs	1,151	(406)	—	745
Financial instrument contracts	21,696	(43,657)	—	(21,961)
Share-based compensation	(442)	(1,238)	(672)	(2,352)
	65,214	(38,929)	(2,011)	24,274

	Balance December 31, 2016 (Asset)/Liability	**Recognized in profit and loss (Recovery)/Expense**	**Recognized in equity (Asset)/Liability**	**Balance December 31, 2017 (Asset)/Liability**
($ thousands)				
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**

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

	December 31, 2017	December 31, 2016
($ thousands)		
Canadian oil and gas property expense	**482,916**	520,994
Canadian development expense	**544,348**	580,171
Canadian exploration expense	**340,252**	322,346
Undepreciated capital cost	**242,015**	271,065
Non-capital losses	**748,026**	651,776
Other	**5,523**	8,028
Total	**2,363,080**	2,354,380

Non-capital losses carry forward of $748.0 million (December 31, 2016 - $651.8 million) expire in the years 2028 through 2037. Bonavista has capital losses of $38.0 million (December 31, 2016 - $5.3 million) available for carry forward against future capital gains indefinitely that are not included in the deferred income tax asset. For the years ended December 31, 2017 and 2016 Bonavista paid no tax installments.

15. Commitments

The following table is a summary of Bonavista's contractual obligations and commitments at December 31, 2017:

	Total	2018	2019	2020	2021	2022 and thereafter
($ thousands)						
Long-term debt repayments(1)(3)	800,544	—	—	200,832	259,726	339,986
Interest payments(2)(3)	136,520	30,095	30,095	28,655	19,857	27,818
Office lease(4)	17,059	6,356	6,760	3,943	—	—
Drilling service contracts(5)	1,449	1,449	—	—	—	—
Drilling and completions capital(6)	14,708	14,708	—	—	—	—
Transportation expenses(7)	209,052	38,073	35,593	30,185	30,958	74,243
Total contractual obligations	**1,179,332**	**90,681**	**72,448**	**263,615**	**310,541**	**442,047**

(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, 2017 of $1.2573 CDN to $1.0000 US dollar.
(4) Office lease expires July 31, 2020.
(5) The drilling service contract is with one service provider with a remaining term of one year.
(6) The drilling and completions capital commitment is with a joint interest partner on lands in Bonavista's Deep Basin Core area.
(7) Includes a Long Term Fixed Price (LTFP) contract with TransCanada for 10 years. This contract contains an early termination policy after 5 years which has been assumed to be exercised in the contractual obligation above.

16. Supplemental disclosure

a. Income statement presentation

Bonavista's statement of loss and comprehensive 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 loss and comprehensive loss:

($ thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Operating	**8,794**	10,097
General and administrative	**23,462**	21,895
Total employee compensation costs	**32,256**	31,992

For the year ended December 31, 2017, $2.7 million (December 31, 2016 - $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 loss and comprehensive loss:

($ thousands)	**Year ended December 31, 2017**	Year ended December 31, 2016
Short-term benefits	**3,437**	3,701
Share-based payments(1)	**7,661**	2,631
Total key management personnel compensation costs	**11,098**	6,332

(1) Share-based payments represent the fair value of restricted 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, 2016	**Cash flows**	**Amortization of debt issue costs**	**Unrealized foreign exchange gain**	**Year ended December 31, 2017**
Bank credit facility	—	**71,091**	**458**	—	**71,549**
Senior unsecured notes	930,221	**(117,880)**	**383**	**(83,729)**	**728,995**
Total financial liabilities from financing activities	930,221	**(46,789)**	**841**	**(83,729)**	**800,544**
Realized foreign exchange loss on repayment of senior unsecured notes(1)		**(32,675)**			
Net repayment of long-term debt from financing activities		**(79,464)**			

(1) Loss on foreign exchange was realized on the principal repayment of US denominated senior unsecured notes on June 4, 2017 (US$25 million) and November 2, 2017 (US$90 million).

CORPORATE INFORMATION

DIRECTORS

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

Jason E. Skehar, *(5)*
President and CEO

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

David Carey *(2)(4)*

Theresa Jang *(1)(3)*

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

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

Ronald J. Poelzer *(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

Wayne E. Merkel,
Vice President, Exploration

Colin J. Ranger,
Vice President, Production

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

Scott W. Shimek,
Vice President, Operations

Scott L. Wilhelm,
Vice President, Engineering

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
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or

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Vice President, Finance and CFO

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