BONAVISTA ENERGY CORPORATION

(TSX:BNP)

FOR IMMEDIATE RELEASE

March 1, 2018

N E W S   R E L E A S E

Announces 2017 Fourth Quarter and Year End Results

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the three months and year ended December 31, 2017. Bonavista delivered 14% growth in adjusted funds flow, six percent growth in proved plus probable reserves and five percent growth in annual production, all while spending within our adjusted funds flow and reducing our debt. Bonavista's Audited Consolidated Financial Statements and Notes, as well as Bonavista's Management's Discussion and Analysis ("MD&A") for the years ended December 31, 2017 and 2016, are available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at http://www.sedar.com and on Bonavista's website at www.bonavistaenergy.com.

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 %

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:

(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. Adjusting 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.

(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.

	Three months ended			
Share Trading Statistics	**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.

BONAVISTA ENERGY CORPORATION

Supplemental Financial Information

Consolidated Statements of Financial Position

As at December 31	2017	2016
($ thousands) (unaudited)		
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	64,496	5,361
Financial instrument contracts	—	2,488
	152,627	178,452
Financial instrument commodity contracts	10,260	3,030
Financial instrument contracts	—	2,343
Property, plant and equipment	2,658,352	2,843,763
Exploration and evaluation assets	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	—	154,334
Current portion of decommissioning liabilities	16,146	20,936
Dividends payable	2,518	2,493
Financial instrument commodity contracts	38,146	53,837
	182,052	349,500
Financial instrument commodity contracts	10,423	35,981
Financial instrument contracts	19,295	469
Long-term debt	800,544	775,887
Other long-term liabilities	6,603	8,816
Decommissioning liabilities	393,180	416,986
Deferred income taxes	7,912	24,274
Total liabilities	1,420,009	1,611,913
Shareholders' equity		
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

BONAVISTA ENERGY CORPORATION

Supplemental Financial Information

Consolidated Statements of Loss and Comprehensive Loss

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
($ thousands, except per share amounts) (unaudited)				
Revenues				
Production	**147,188**	141,842	**553,002**	445,434
Royalties	**(8,066)**	(12,767)	**(41,677)**	(36,903)
Production revenues, net of royalties	**139,122**	129,075	**511,325**	408,531
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)
Production revenues, net of royalties and financial instrument commodity contracts	**138,620**	38,951	**644,505**	338,373
Expenses				
Operating	**38,343**	36,700	**147,165**	140,592
Transportation	**7,584**	5,512	**24,871**	22,566
General and administrative	**6,819**	6,948	**24,749**	27,138
Share-based compensation	**2,614**	2,058	**15,702**	8,994
Gain on disposition of property, plant and equipment	**(135)**	(63,645)	**(13,589)**	(66,354)
Loss (gain) on disposition of exploration and evaluation assets	**963**	(28,540)	**(976)**	(23,738)
Depletion, depreciation, amortization and impairment	**280,514**	64,313	**469,555**	319,845
Total expenses	**336,702**	23,346	**667,477**	429,043
Income (loss) from operating activities	**(198,082)**	15,605	**(22,972)**	(90,670)
Finance costs	**30,517**	34,541	**104,938**	128,717
Finance income	**(13,790)**	(7,663)	**(83,729)**	(84,460)
Net finance costs	**16,727**	26,878	**21,209**	44,257
Loss before taxes	**(214,809)**	(11,273)	**(44,181)**	(134,927)
Deferred income tax (recovery)	**(55,660)**	748	**(16,251)**	(38,929)
Net loss and comprehensive loss	**(159,149)**	(12,021)	**(27,930)**	(95,998)
Net loss and comprehensive loss per share				
Basic	**(0.62)**	(0.05)	**(0.11)**	(0.40)
Diluted	**(0.62)**	(0.05)	**(0.11)**	(0.40)

BONAVISTA ENERGY CORPORATION

Supplemental Financial Information
Consolidated Statements of Changes in Equity

For the years ended December 31	Shareholders' Capital	Exchangeable Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
($ thousands) (unaudited)					
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**

BONAVISTA ENERGY CORPORATION

Supplemental Financial Information
Consolidated Statements of Cash Flows

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
($ thousands) (unaudited)				
Cash provided by (used in):				
Operating Activities				
Net loss and comprehensive loss	**(159,149)**	(12,021)	**(27,930)**	(95,998)
Adjustments for:				
Depletion, depreciation, amortization and impairment	**280,514**	64,313	**469,555**	319,845
Share-based compensation	**2,614**	2,058	**15,702**	8,994
Unrealized losses (gains) on financial instrument commodity contracts	**9,187**	99,807	**(107,614)**	161,930
Gain on disposition of property, plant and equipment	**(135)**	(63,645)	**(13,589)**	(66,354)
Loss (gain) on disposition of exploration and evaluation assets	**963**	(28,540)	**(976)**	(23,738)
Net finance costs	**16,727**	26,878	**21,209**	44,257
Deferred income tax (recovery)	**(55,660)**	748	**(16,251)**	(38,929)
Decommissioning expenditures	**(5,746)**	(6,637)	**(17,318)**	(15,309)
Changes in non-cash working capital items	**5,200**	(12,200)	**2,831**	(33,906)
Cash flow from operating activities	**94,515**	70,761	**325,619**	260,792
Financing Activities				
Issuance of equity, net of issue costs	**—**	(2)	**—**	110,032
Dividends paid	**(2,517)**	(2,492)	**(10,015)**	(13,538)
Interest paid	**(18,048)**	(19,944)	**(39,344)**	(45,770)
Net repayment of long-term debt	**(45,227)**	(43,879)	**(79,464)**	(258,035)
Cash flow used in financing activities	**(65,792)**	(66,317)	**(128,823)**	(207,311)
Investing Activities				
Exploration and development	**(59,722)**	(58,574)	**(289,029)**	(153,871)
Property acquisitions	**(2,961)**	(2,555)	**(13,736)**	(12,166)
Property dispositions	**5,035**	120,221	**21,577**	180,071
Office equipment	**(9)**	(110)	**(557)**	(604)
Changes in non-cash working capital items	**(10,617)**	22,551	**(1,028)**	19,066
Cash flow from (used in) investing activities	**(68,274)**	81,533	**(282,773)**	32,496
Change in cash	**(39,551)**	85,977	**(85,977)**	85,977
Cash, beginning of period	**39,551**	—	**85,977**	—
Cash, end of period	**—**	85,977	**—**	85,977

This document 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 and the Management's Discussion and Analysis, 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.*

Non-GAAP Measures - Throughout this document, 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 this document and should be read in conjunction with 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 - Management also makes reference to the following oil and gas terms in this document: "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

This document 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. This document 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 documents 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.

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 this document 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. This document also contains future-oriented financial information and financial outlook information (collectively, "FOFI") about our prospective results of operations and adjusted funds flow, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. 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 FOFI and forward-looking statements. Bonavista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and FOFI, or if any of them do so, what benefits Bonavista will derive therefrom. Bonavista has included the forward-looking statements and FOFI in this document in order to provide readers with a more complete perspective on Bonavista's future operations and such information may not be appropriate for other purposes. 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.

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