BONAVISTA ENERGY CORPORATION

(TSX:BNP)
FOR IMMEDIATE RELEASE
May 2, 2019
N E W S R E L E A S E

Announces 2019 First Quarter Results

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the three months ended March 31, 2019. The financial statements and notes, as well as management's discussion and analysis, 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.

MESSAGE TO SHAREHOLDERS

Through the first three-months of 2019, we directed a moderate 75% of our adjusted funds flow to our capital program as we pragmatically navigate the current and future commodity price discounts created by regulatory uncertainty and inadequate pipeline capacity in the Canadian energy sector.

Capital expenditures, net of acquisition and divestiture activity in the quarter were $43.8 million. 70% of our exploration and development ("E&D") spending was allocated to drilling ten gross (9.6 net) wells, primarily in our West Central core area. The remaining 30% was allocated to support capital, the majority of which was directed to land and infrastructure spending.

Additional Duvernay mineral rights were acquired in the quarter, firmly establishing our presence in this emerging liquids-rich resource play with access now to approximately 190 prospective sections. Currently, we plan to drill our first Duvernay horizontal well in the second half of this year.

Infrastructure projects initiated in the first quarter will lead to total spend of approximately $15 million on such projects in the first half of 2019, most of which are concentrated in our West Central core area. This will allow us to redirect current and future production in the Willesden Green area to a lower cost, efficient processing solution.

Production for the quarter was recorded modestly ahead of budget despite severe cold temperatures in the later-half of the first quarter leading to unanticipated production downtime. Natural gas liquids ("NGL") and oil production account for 30% of the total, marking a four percent increase in our oil and liquids weighting over the prior year period.

Natural gas prices were buoyed in the first quarter by the extended period of extreme cold in the province, providing us an opportunity to hedge an incremental 28 mmcf per day for the summer period of 2019 at an average price of $1.31 per mcf. When combined with other diversification initiatives, we have less than 20% of our forecasted natural gas production exposed to spot AECO pricing over the summer period of 2019.

2019 FIRST QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- Sustained production at 66,937 boe per day within two percent of prior quarter production rates while spending only 75% of adjusted funds flow;
- Executed an E&D capital program of $49.0 million, drilling ten gross (9.6 net) wells while completing eight gross (7.6 net) wells. Our focus remains on drilling liquids rich prospects, with seven of our ten wells drilled in our West Central area;
- Divested of a sour natural gas non-core asset producing 442 boe per day at closing for net proceeds of $5.4 million;
- Generated $58.2 million ($0.22 per share) in adjusted funds flow, six percent ahead of forecast;
- Recorded cash costs of $9.55 per boe, slightly below forecast but in excess of prior quarter resulting from a modest increase in operating expenses due to the cold weather experienced in February and March;
- Strengthened our position in the emerging Duvernay play by acquiring land in the Pembina area bringing our total prospective lands to over 121,000 acres within our core areas; and
- Protected 2019 adjusted funds flow through the summer period, when NGTL maintenance activities escalate, with 75% of our forecasted 2019 natural gas production hedged at an average price of $2.11 per mcf.

	Three Months Ended			
	December 31, 2018	**March 31, 2019**	March 31, 2018	% Change
Financial				
($ thousands, except per share)				
Production revenues	124,302	**120,636**	138,388	(13)%
Net income (loss)	81,227	**(40,135)**	(2,037)	1,870 %
Per share[1]	0.31	**(0.15)**	(0.01)	1,400 %
Cash flow from operating activities	77,581	**54,485**	76,048	(28)%
Per share[1]	0.30	**0.21**	0.30	(30)%
Adjusted funds flow[2]	61,075	**58,181**	69,128	(16)%
Per share[1]	0.23	**0.22**	0.27	(19)%
Dividends declared	2,555	**2,558**	2,523	1 %
Per share	0.01	**0.01**	0.01	— %
Total assets	2,923,709	**2,867,965**	2,933,854	(2)%
Shareholders’ equity	1,552,184	**1,512,870**	1,539,073	(2)%
Long-term debt	801,625	**781,168**	802,394	(3)%
Net debt[2]	835,905	**811,440**	839,619	(3)%
Capital expenditures:				
Exploration and development	45,172	**49,023**	43,855	12 %
Acquisitions, net of dispositions[3]	11,037	**(5,378)**	97	(5,644)%
Corporate	221	**119**	145	(18)%
Weighted average outstanding equivalent shares: (thousands)[1]				
Basic	260,047	**260,305**	257,030	1 %
Diluted	267,135	**272,236**	267,120	2 %
Operating				
(boe conversion – 6:1 basis)				
Production:				
Natural gas (mmcf/day)	281	**282**	322	(12)%
Natural gas liquids (bbls/day)	19,131	**17,945**	16,480	9 %
Oil (bbls/day)[4]	2,108	**1,988**	2,327	(15)%
Total oil equivalent (boe/day)	68,011	**66,937**	72,417	(8)%
Product prices:[5]				
Natural gas ($/mcf)	2.91	**2.61**	2.85	(8)%
Natural gas liquids ($/bbl)	24.99	**28.95**	31.68	(9)%
Oil ($/bbl)[4]	28.47	**60.21**	59.81	1 %
Total oil equivalent ($/boe)	19.91	**20.54**	21.79	(6)%
Operating expenses ($/boe)	5.66	**5.85**	5.64	4 %
Transportation expenses ($/boe)	1.37	**1.44**	1.23	17 %
General and administrative expenses ($/boe)	0.87	**0.84**	1.09	(23)%
Cash costs ($/boe)[2]	9.27	**9.55**	9.38	2 %
Operating netback ($/boe)[2]	11.99	**11.92**	13.11	(9)%

NOTES:

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

Share Trading Statistics	Three months ended March 31, 2019	December 31, 2018	September 30, 2018	June 30, 2018
($ per share, except volume)				
High	1.39	1.60	1.63	1.75
Low	1.06	1.01	1.25	1.13
Close	1.11	1.20	1.49	1.49
Average Daily Volume - Shares	531,298	817,647	527,770	1,086,460

TWO CORE AREAS

We remain committed to disciplined reinvestment levels, generating free cash flows from our operating activities to allocate towards the reduction of our net debt. Net capital expenditures for the first quarter were $43.8 million, which equates to 75% of our adjusted funds flow. E&D expenditures were $49.0 million with $34.2 million allocated to drilling 9.6 net wells and completing 7.6 net wells. The remaining $14.8 million was spent on support capital, most notably a crown land acquisition in the Duvernay and infrastructure projects in West Central. Dispositions in the quarter totaled $5.4 million, with virtually no capital directed to acquisition expenditures.

Deep Basin Operations

For Q1 2019, 32% of E&D capital was invested in our Deep Basin core area. With E&D expenditures of $15 million, $14 million was allocated to value projects where we drilled two Ansell Wilrich wells and participated in the drilling of one non-operated Cardium well. At Ansell, we finished drilling a three well pad which we completed at the end of February. Unfortunately, excessive frac interference resulted in the initial 40% reduction in performance relative to expectations. We will continue to monitor and anticipate performance to converge closer to expectations with time.

Despite the Ansell new well underperformance, Q1 2019 production in our Deep Basin core area averaged 24,097 boe per day which was within one percent of our forecast. This was achieved mainly due to increased production at our Edson area. The Notikewin well drilled at Edson in the final months of 2018 has averaged 8.4 mmcf per day over its first 90 days of production which is similar to the initial Notikewin well on production in Q1 2018. To take advantage of the cold weather induced high pricing in February, modifications were made to our compression facilities at Edson to increase capacity and remove flowing pressure restrictions.

With our focus on liquid rich development, the Deep Basin core are will have limited activity for the remainder of 2019. The plan is to drill two to four more wells targeting the Spirit River formations.

West Central Operations

For Q1 2019, 66% of exploration and development (E&D) capital was invested in our West Central core area. With E&D expenditures of $33 million, $20 million was allocated to value capital and $13 million was allocated to support capital. During the quarter, we drilled seven gross (7.0 net) wells consisting of four in the Glauconite formation and three in the Falher formation. Of these wells, four wells have been completed in the quarter with three wells to be completed in the second quarter. The first two Falher wells have averaged 5.8 mmcf per day over the first 60 days on production which exceeds our forecast by 38%. The two Glauconite wells completed at the end of the quarter have just recently been brought on production and are meeting expectations.

Average Q1 2019 production in our West Central core area was 40,741 boe per day comprised of 59% natural gas and 41% oil and liquids.

For the remainder of the year, the plan is to drill 12 to 18 wells in our West Central core area mainly focused on the Glauconite play. To accommodate this development we are investing $20 million of support expenditures to expand pipeline and compression infrastructure at Strachan and Willesden Green in the second and third quarters of 2019.

Duvernay Expansion

In Q1 2019, we invested $6.2 million in our West Central core area to further expand our Duvernay land position. This brings our total exposure in the Duvernay light oil and condensate rich gas windows to approximately 190 sections. Our initial appraisal of the Duvernay will be undertaken in the Pembina area with our first horizontal well to be drilled in the second half of 2019.

Q1 2019 Production

Production for the quarter averaged 66,937 boe per day comprised of 282 mmcf per day of natural gas, 17,945 bbls per day of natural gas liquids and 1,988 bbls per day of oil. This production rate was modestly ahead of forecasted volumes and was achieved despite the extreme cold weather impacting operations throughout the quarter. Our commitment to allocating capital to liquids rich projects over the past year has increased our oil and natural gas liquids ratio to 30% of our total production volumes, four percent higher than the same period last year.

Q1 2019 Production Revenue, Marketing and Risk Management

Production revenues for the first quarter, inclusive of $3.1 million of realized gains on financial instrument commodity contracts, was $123.7 million, or $20.54 per boe which was within one percent of the prior quarter. Production revenues, excluding realized gains on financial instrument commodity contracts was $120.6 million or $20.02 per boe. Realized pricing for natural gas was $2.61 per mcf, a ten percent reduction from the previous quarter but ahead of the average AECO daily spot price for the quarter of $2.49 per mcf and a 42% premium to the average AECO monthly index price of $1.84 per mcf. Financial hedging accounted for a premium of $0.09 per mcf and $0.57 per bbl for natural gas and natural gas liquids respectively, and a discount of $0.32 per bbl on realized oil pricing.

Q1 2019 Operating and Transportation Expenses

Operating expenses in the quarter were $5.85 per boe, in line with our forecast but an increase from $5.66 per boe from the prior quarter, reflecting the seasonal impact of increased operating expenses.

Transportation expenses were one percent higher in the quarter at $8.7 million compared to $8.6 million in the previous quarter and on a per boe basis transportation expenses were $1.44 per boe as compared to $1.37 per boe. Natural gas transportation on an absolute and per boe basis in the quarter remained flat to the previous quarter but natural gas liquids and oil transportation came in higher on both an absolute and per boe basis due to one-time prior period adjustments. Unutilized firm natural gas transportation expenses on the NGTL system of $1.0 million were included in the first quarter transportation costs.

Q1 2019 General and Administrative and Interest Expenses

First quarter general and administrative expenses were $5.1 million, or $0.84 per boe, six percent lower than the fourth quarter of $5.4 million. The adoption of IFRS 16, *Leases*, resulted in a decrease of $1.0 million due to the accounting treatment of our head office lease, this was offset by higher compensation costs typically associated in the beginning of the year, in addition to higher transaction cost due to the sale and potential sale of assets.

Interest expense for the quarter was $8.5 million down slightly from the fourth quarter of 2018 at $8.6 million and in line with our budget.

Q1 2019 Cash Flow from Operating Activities and Adjusted Funds Flow

Cash flow from operating activities was 30% lower in the first quarter relative to the previous quarter at $54.5 million from $77.6 million primarily associated with a $18.8 million change in working capital quarter over quarter. Adjusted funds flow of $58.2 million for the quarter, was five percent lower than the $61.1 million recorded in the fourth quarter of 2018 due to higher royalty expenses and modestly higher cash costs.

Q1 2019 Long-term Debt

A $20.5 million reduction in long-term debt to $781.2 million over the fourth quarter, can be attributed to debt repayment of $4.2 million and the strengthening Canadian dollar experienced in the first quarter of 2019 as compared to year end 2018.

OUTLOOK

The short-term balance between the global supply and demand for energy remains far from certain as evidenced by the extreme volatility in the local and global price for oil and natural gas. In the past six months alone, Brent crude prices have fluctuated between $51 per bbl and $86 per bbl, WTI prices have swung between $43 per bbl and $76 per bbl while the global spot price for LNG has oscillated between $5 per mmbtu and $11 per mmbtu. The volatility in western Canadian prices have been amplified even further with insufficient export capacity for both oil and natural gas. At times over the past six months, western Canadian natural gas prices have traded at 70% discount to NYMEX, while western Canadian Select oil price has been discounted as much as 88% relative to WTI.

Notwithstanding this short-term uncertainty, long-term global demand for energy, is set to rise by nearly 30% by 2040, according to IEA World Energy Outlook 2018. A growing population augmented by the urbanization and industrialization of emerging economies will lift the standard of living across the world, most notably in countries like China and India.

This same IEA outlook forecasts that global natural gas demand is set to rise by 43% by 2040, overtaking coal as the world’s second largest energy source by 2030. More than half of this demand growth is forecasted in developing economies like China and South East Asia where bold air quality policies have recently been enacted. Across the globe, household and ambient air pollution is said to contribute to more than seven million premature deaths per year, 60% of which occur in China, India and South East Asia where nearly two-thirds of the population rely on solid fuels such as dung, wood or charcoal as their primary fuel for cooking and heating.

China’s commitment to replacing coal consumption with natural gas was resoundingly clear in 2017 with a 30% annual increase in LNG imports. Estimates show that by 2040 about 1,500 megatonnes of carbon dioxide equivalent emissions could be eliminated every year if new power plants in China, India and Southeast Asia are fueled by natural gas from LNG instead of coal. Global annual LNG trade in 2017 rose a staggering 14% and solidifies the predictions that the Asia Pacific region will account for approximately 80% of global LNG imports by 2040.

North America, with our proximity to South Asia will undoubtedly play a role in this LNG demand forecast and Canada, with the fourth largest natural gas reserves in the world, has an opportunity to participate. With LNG facilities on Canada’s west coast being closer than any other North American LNG source, there is a window of opportunity emerging. This global opportunity is real, and this demand will undeniably get met with production from another jurisdiction if Canada cannot find a way to create a stable and competitive fiscal environment with regulatory efficiency and excellence.

Today, Canadian natural gas growth is limited by pipeline infrastructure bottlenecks and a lack of LNG export infrastructure. This lack of egress from our world-class sedimentary basin has resulted in severe discounts to world prices. After 10 years and 20 LNG export proposals on our west coast, we are grateful to have our first project, LNG Canada to reach FID with anticipation of an expansion project not far behind. Similarly, we have line-of-sight to resolve the pipeline bottlenecks that currently prohibit western Canada from consuming and exporting an incremental 3.1 bcf per day with a final in-service date of 2021. Notwithstanding a broken regulatory system prohibiting projects like these to be completed, free from delay and incremental cost pressures, western Canada will soon have the opportunity to better serve countries in need our abundant natural gas resources, developed under leading social and environmental standards.

Estimates show that annually, for every 1 bcf per day of incremental production to serve LNG export in Canada, 10,000 direct and indirect jobs are created, $340 million in revenues are created for provincial and federal governments and $2.4 billion of direct and indirect economic activity is created. LNG created in Canada presents both economic prosperity and global emission reduction provided the most robust and thoughtful energy policies are pursued by our federal and provincial governments. With a deliberate goal to become the most responsible and efficient provider of energy, Canada can be the natural gas provider of choice for many countries in need.

At Bonavista, we remain committed to strengthening our foundation while the short-term egress challenges are forcing many producers in western Canada to sell their molecules at some of the lowest natural gas prices in the world.

In 2019 we will focus on enhancing revenue and reducing costs to maximize free cash flow. As demonstrated in 2018 and year-to-date in 2019, we will remain opportunistic as we strategically enhance our asset quality via A&D activity, land acquisition and infrastructure development. Many of these opportunities may not result in immediate financial accretion but will undoubtedly result in long-term value creation.

As a result of the near term outlook for commodity prices, the Board of Directors suspended Bonavista's quarterly dividend. We estimate that this action will reduce annual cash outlays for 2019 by approximately $8 million. We will continue to review the dividend program on a quarterly basis, however this suspension is a necessary step to support our financial flexibility in the current commodity price environment.

2019 guidance remains consistent with our message in February. We expect to spend between $130 and $170 million with plans to drill between 24 and 32 wells. This should result in production levels averaging between 65,000 and 69,000 boe per day, a function of the uncertainty surrounding the impact of NGTL maintenance activities and midstream turnaround activities this summer. We expect to exit 2019 near 67,000 boe per day, a similar production levels as to where we entered the year.

Balance sheet flexibility will remain our #1 priority as we expect natural gas prices to remain volatile and unpredictable while export capacity for all products out of western Canada remain constrained. We will continue to rely on the predictable and reliable performance of our asset base to exercise financial prudence as we build a solid foundation for growth in value in the future.

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

NON-GAAP MEASURES

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

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

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

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

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

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

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

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

- "Net debt" is equal to Bonavista's bank credit facility and senior unsecured notes, net of working capital (excluding associated assets and liabilities from financial instrument commodity contracts, lease liabilities and decommissioning liabilities).

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

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

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

Reference should be made to our first quarter 2019 condensed consolidated interim financial statements for additional disclosure on these non-GAAP measures, including reconciliations to the most comparable GAAP measure.

OIL AND GAS ADVISORIES

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

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

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

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.

The following abbreviations used in this news release have the meanings set forth below:

Bbls	barrels
Mbbls	thousand barrels
Boe	barrels of oil equivalent
Mcf	thousand cubic feet
MMcf	million cubic feet
$000's	thousands of dollars

FORWARD-LOOKING INFORMATION

This document should be read in conjunction with the Management's Discussion and Analysis ("MD&A") and the condensed consolidated interim financial statements for the three months ended March 31, 2019, together with notes related thereto, as well as in conjunction with the audited consolidated financial statements for the year ended December 31, 2018, together with the notes thereto, for a full understanding of the financial position and results of operations of Bonavista Energy Corporation ("Bonavista" or the "Corporation"). Additional information relating to Bonavista, including the audited consolidated financial statements for the year ended December 31, 2018, are available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

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

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

- our focus and plans to create maximum shareholder value;
- expectations regarding our financial flexibility in the future;
- our ability to navigate current and future commodity prices;
- expectations regarding the quality, predictability, resilience and sustainability of our asset base;
- expectations regarding well performance;
- the performance characteristics of our oil and natural gas properties;
- our exploration and development plans and the results therefrom;
- expectations regarding industry conditions, future commodity prices and demand for natural gas;
- our 2019 capital expenditure budget;
- our ability to be agile in responding to changes to commodity prices;
- expectations for 2019 for production volumes, adjusted funds flow, net debt and payout ratio;
- expectations of future production rates, volumes and production mixes;
- our acquisition and infrastructure plans;
- expectations regarding the number and quality of our undeveloped locations; and
- our focus on creating incremental financial flexibility.

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

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

These forward-looking statements are made as of the date of this news release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

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