MANAGEMENT DISCUSSION AND ANALYSIS

For the three month period ended March 31, 2017

The following management discussion and analysis ("MD&A") of the financial conditions and results of operations of Canadian Spirit Resources Inc. ("CSRI" or the "Corporation") for the three months ended March 31, 2017 should be read in conjunction with the unaudited interim condensed financial statements for the same period, as well as the MD&A and audited financial statements for the year ended December 31, 2016 prepared under International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee. The financial data presented herein is in accordance with IFRS and all amounts are presented in Canadian dollars. This MD&A has been prepared by management and includes information up to May 29, 2017, the date of review and approval by the Corporation's Board of Directors.

Corporate Overview

CSRI is a natural resources company whose shares are listed under the trading symbol 'SPI' on the TSX Venture Exchange (the "Exchange") focused on the exploration and development of opportunities in the unconventional natural gas resource sector of the energy industry. Operating on its own 100% working interest lands, and together with its joint venture partner, Canbriam Energy Inc. ("Canbriam"), the Corporation's principal activity is exploring and developing the productive capability of its Montney unconventional natural gas and natural gas liquids play in the Farrell Creek/Altares area of northeastern British Columbia. The Corporation commenced natural gas production from the Montney Formation in 2011.

Selected Quarterly Information

The following is a summary of the results of the Corporation for the eight most recently completed quarters *(000's, unless otherwise indicated)*:

	2017	2016				2015		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Average sales volumes								
- natural gas (MMcf/d)	**0.74**	1.10	-	-	0.63	0.57	0.74	0.75
Sales price (per Mcf)	**$ 2.48**	$ 2.37	$ -	$ -	$ 1.41	$ 1.06	$ 1.82	$ 2.07
Total sales volumes								
- natural gas (MMcf)	**66.3**	101.1	-	-	57.7	52.7	68.2	67.8
Natural gas sales	**$ 164**	$ 240	$ -	$ -	$ 84	$ 54	$ 123	$ 140
Operating netbacks	**$ 88**	$ 190	$ (54)	$ (80)	$ (20)	$ (20)	$ 21	$ (3)
Net cash flows from operating activities	**$ (104)**	$ (133)	$ 203	$ (164)	$ (407)	$ (213)	$ (144)	$ (269)
Net income (loss)	**$ (301)**	$ (29,356)	$ 111	$ (682)	$ (142)	$ (376)	$ (978)	$ (473)
Net income (loss) per share	**$ (0.00)**	$ (0.19)	$ 0.00	$ (0.01)	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)
Net working capital	**$ 817**	$ 1,156	$ 1,214	$ 1,259	$ 1,232	$ 3,142	$ 1,772	$ 2,144
Total assets	**$ 45,021**	$ 45,673	$ 74,562	$ 74,485	$ 75,649	$ 73,618	$ 71,738	$ 72,722
Shareholders' capital	**$ 42,689**	$ 42,978	$ 71,859	$ 71,727	$ 71,772	$ 70,886	$ 69,311	$ 70,262
Common shares outstanding	**156,759**	156,759	152,592	152,592	146,192	141,367	128,867	128,867
Net capital expenditures	**$ 45**	$ 183	$ 275	$ 391	$ 3,096	$ 228	$ 200	$ 134

Note:
1. Quarterly amounts may not total or calculate to year-to-date amounts due to rounding.

Production has remained relatively constant due to the lower decline rate associated with the wells being in the stable stages of their production life. Price volatility, due to excess North American gas supply over the past few years, has had a significant negative impact on Canadian natural gas producers. The average natural gas sales price the Corporation realized from its production fell steadily from 2014 to early 2016. As a result, CSRI and Canbriam decided to shut-in all joint venture natural gas production at Farrell

Creek/Altares from March 31, 2016 until October 4, 2016 when a steady increase in natural gas prices justified re-starting production.

In the third quarter 2016, the Corporation agreed to a proof of loss settlement of an operator's extra expense/well control insurance claim for an amount of $425,000 relating to the c-69-H/94-B-1 well that was drilled in the first quarter 2016. Together, the settlement and subsequent receipt of the insurance proceeds are considered a separate economic event from the drilling of the well, and are therefore accounted for separately from the well drilling costs. As a result, an amount of $425,000 was recorded in the third quarter 2016 as other income, while the original cost to drill the well in the first quarter 2016 remains capitalized within exploration and evaluation assets.

The Corporation performed impairment tests as at December 31, 2016 to assess the recoverable value of E&E assets of both the Corporation's Farrell Creek Montney Formation project and the Farrell Creek Gething Formation project. Estimates of fair value less costs of disposal for the Montney E&E assets were determined in part using merger and acquisition metrics, prevailing land tender prices in the Farrell Creek area, as well as reserve values as at December 31, 2016 prepared by independent reservoir engineering consultants. Based on these and other factors, the estimated recoverable amount of the Montney E&E assets was calculated to be greater than the carrying value and as such there was no impairment. However, the estimated recoverable amount of the Gething E&E assets, determined in part by project status as well as feasible future development opportunities available, was found to be impaired as compared to the carrying value. As such, an impairment of natural gas costs for the Gething E&E assets of $29.1 million was recorded in the statement of operations in the fourth quarter 2016.

The lack of pipeline take away capacity for the rapidly growing natural gas production that has been discovered in the Montney Formation in northeastern British Columbia has resulted in large volumes of natural gas being trapped behind the sales point at Station 2, the benchmark pricing point on the Spectra pipeline system. This has placed further downward pressure on prices for natural gas producers in northeastern British Columbia. On March 20, 2017, TransCanada Corporation filed a variance application with the National Energy Board to proceed with construction of the North Montney Mainline project in northeastern British Columbia. TransCanada Corporation has secured new 20 year commercial contracts with 11 shippers for approximately 1.5 Bcf per day of firm service. The North Montney Mainline will cross CSRI's lands and provide new egress for natural gas production into Alberta and other North American markets. Construction is anticipated to begin in the first half 2018 with initial startup in April 2019.

Fresh Water Sourcing

The Williston Reservoir Water Pipeline Project (25% owned by CSRI; operated by Canbriam) is able to deliver up to 10,000 m^3/d of fresh water from the Williston Reservoir to the Farrell Creek/Altares area in northeastern British Columbia on a year-round basis until December 31, 2031. The project will reduce, by approximately $500,000 per well, the cost of delivering a secure supply of fresh water used in the fracture stimulation of both vertical and horizontal wells and will lessen the impact on local communities and infrastructure by reducing the need to transport fresh water overland by truck to drilling sites. Access to water is a major concern for many oil and gas companies operating in northeastern British Columbia.

Montney Formation Reserves

An independent reserve evaluation covering the Montney Formation at Farrell Creek/Altares was prepared by GLJ Petroleum Consultants ("GLJ"), an independent qualified reserves evaluator, as at December 31, 2016 in accordance with the reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook. The evaluation is based on a plan to drill and complete four additional Montney wells over the next few years to further develop the Montney lands at Farrell Creek/Altares. Proceeding with full development will be contingent upon factors such as access to capital, economic price conditions, infrastructure, and environmental and regulatory matters. For more information, the Corporation's Form 51-101F1 Statement of Reserves Data and Other Oil and Gas Information and related documents have been filed on SEDAR at www.sedar.com and on the Corporation's website at www.csri.ca

Montney Formation Resource Assessment

GLJ was also engaged to prepare an independent resource assessment of the Montney Formation on the Corporation's Farrell Creek/ Altares lands in northeastern British Columbia as at December 31, 2016 with respect to the Total Petroleum Initially-In-Place ("TPIIP"), Discovered Petroleum Initially-In-Place ("DPIIP") and Undiscovered Petroleum Initially-In-Place ("UPIIP") in accordance with the resource definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook. This independent assessment has resulted in 9,044 Bcf (9.0 Tcf) of TPIIP, comprised of 4,029 Bcf (4.0 Tcf) of DPIIP and 5,015 Bcf (5.0 Tcf) of UPIIP, of shale gas being recognized on the Corporation's Montney lands. This represents a 62% increase in TPIIP available for exploitation and development as was previously recognized in the Farrell Creek Montney Resource Assessment conducted by GLJ effective February 29, 2012.

Results from Operations

Natural Gas Production and Revenues

	Three months ended March 31,			
		2017		**2016**
Total sales volumes of natural gas (Mcf)		**66,259**		57,736
Average sales volumes of natural gas (1)				
Mcf/d		**738**		635
boe/d		**123**		106
Total natural gas sales ($)	**$**	**164,102**	$	83,978
Average sales price of natural gas				
$/Mcf	**$**	**2.48**	$	1.41
$/boe	**$**	**14.86**	$	8.46

Total production volumes in the first quarter 2017 increased by 14.8% compared to the first quarter 2016 due to the continued flush production resulting from well bore pressure buildup as a result of the wells being shut-in for approximately six months during the middle part of 2016. The Corporation's first month of post shut-in net production averaged 1.32 MMcf/d.

Due to the low natural gas price environment and the focus of CSRI's joint venture partner on their own 100% working interest lands at Altares, the Corporation has not added any new production over the last six years, and is therefore subject to the inherent declines associated with each producing natural gas well. Although the rate of decline has diminished, future production additions are required to alleviate this decline.

Royalties

The five Montney Formation wells tied into the Farrell Creek/Altares Montney joint venture gas plant are all deep horizontal wells and as such, each of these producing wells qualifies for the British Columbia Government's Deep Royalty Credit Program. This Program generates up to $2.81 million (gross) in royalty credits for each well and the royalty credits are drawn down over time as the wells produce natural gas. Commencing with the second quarter 2013, the British Columbia Government introduced a minimum 3% royalty which is applicable to wells within the Deep Royalty Credit Program. Royalty credits that were previously generated from the discontinued Summer Drilling Credit Program can be used to offset this minimum royalty. Between these two well royalty credit programs, and at the rates of production experienced to date in 2017 the Corporation will not have to actually remit any crown royalties to the British Columbia Government for the next five years or more. Royalty credits applied are accounted for as an offset against the capital costs accumulated within Property, Plant and Equipment ("P,P&E").

Operating Netbacks

During the three months ended March 31, 2017, the Corporation applied $6,527 (2016: $532) of royalty credits against crown royalties that would otherwise have been payable.

For the three months ended March 31, 2017					**$/Mcf**		**$/boe**
Natural gas sales	**$**	**164,102**		**$**	**2.48**	**$**	**14.86**
Royalties expense		**(6,527)**	*4.0%*		**(0.10)**		**(0.59)**
Net revenue		**157,575**			**2.38**		**14.27**
Royalty credits applied		**6,527**			**0.10**		**0.59**
Operating costs		**(75,872)**			**(1.15)**		**(6.87)**
Operating netbacks	**$**	**88,230**		**$**	**1.33**	**$**	**7.99**

For the three months ended March 31, 2016					**$/Mcf**		**$/boe**
Natural gas sales	$	83,978		$	1.41	$	8.46
Royalties expense		(532)	*0.6%*		(0.01)		(0.06)
Net revenue		83,446			1.40		8.40
Royalty credits applied		532			0.01		0.06
Operating costs		(103,782)			(1.80)		(10.79)
Operating netbacks	$	(19,804)		$	(0.39)	$	(2.33)

Operating Costs

Operating costs, which have fixed and variable rate components, relate to the Corporation's share of plant maintenance, supervision and other production expenses in conjunction with the five producing Montney Formation wells at Farrell Creek/Altares. Operating costs also include transportation costs to transfer the natural gas from the pipeline system at Farrell Creek/Altares to the sales point at Spectra Station 2 and the British Columbia provincial carbon taxes.

Operating costs, both on an overall and on a per Mcf basis, have decreased from the first quarter 2016 to the first quarter 2017, as the tables for ***Operating Netbacks*** above show. The decrease is a result of reduced well servicing and plant maintenance costs as well as a continued effort by the Corporation's joint venture partner, Canbriam, to reduce and control on-going operating costs at Farrell Creek/Altares. However, as production continues to decline, the fixed component of field operations remains relatively constant and thus the per unit cost is expected to increase. In addition, lower volume throughput requires more operational attention at the Farrell Creek/Altares Montney joint venture natural gas plant, such as a continued higher level of operating costs on a gross basis due to additional costs associated with natural gas recycling at the plant due to the lower volumes.

Depletion

Depletion of Developed and Producing P,P&E is calculated using the unit of production method based on proved plus probable reserves. The depletion expense for the three month period ended March 31, 2017 of $78,788 (2016: $66,587) equates to $1.19 per Mcf (2016: $1.15 per Mcf). The increase in depletion for the respective three month periods, on both a gross and per Mcf basis, is due to the increase in production (see ***Natural Gas Production and Revenues*** on page 3).

Liquidity and Capital Resources

The Corporation's capital expenditures for the three month periods ended March 31, 2017 and 2016 are detailed in the following table:

	Three months ended March 31, 2017	2016
Lease acquisitions and retentions	**$ 67,677**	$ 74,632
Net expenditure on drilling, completion and facilities costs	**74,601**	2,828,723
Other capitalized amounts	**(97,511)**	192,895
Total net capital expenditures	**$ 44,767**	$ 3,096,250

For the three month period ended March 31, 2017, net capital expenditures totaled $0.1 million (2016: $3.1 million), compared to an allocated budgeted capital expenditure of $0.2 million (2016: $3.0 million). For the three months ended March 31, 2016, the main component of the drilling, completion and facilities total of $2.8 million was the costs related to the drilling of the c-69-H/94-B-1 100% working interest vertical well for land retention and resource delineation purposes on the Corporation's western block of lands.

As at March 31, 2017, the Corporation had a net working capital balance of $0.8 million consisting of cash in the amount of $0.8 million and accounts receivable and prepaids of $0.2 million, offset by accounts payable and other accrued liabilities of $0.2 million.

CSRI's capital budget is approved on an annual basis, and subsequently reviewed quarterly, by the Corporation's Board of Directors. The Board of Directors has approved a base capital expenditure budget for 2017 of $0.6 million (net), primarily for lease rental and maintenance capital, but also including an estimated $0.3 million for capitalized overhead.

CSRI has budgeted for cash administration expenses (general and administrative expenses excluding share-based compensation) for 2017 to total $1.1 million (a reduction of 6.2% from 2016 budgeted expenses) before capitalization of exploration and development related overhead, and has budgeted for operating netbacks from the Farrell Creek/Altares Montney operations for 2017 of $0.2 million (2016: $0.1 million).

Reclamation and Abandonment Management

For operations in British Columbia, the Corporation is required to provide deposits towards future abandonment and reclamation costs based on the number of wells and facilities for which the Corporation is the primary permit holder. Based on a Liability Management Rating ("LMR") review performed by the British Columbia Oil and Gas Commission ("BCOGC") in 2011, the Corporation was assessed an initial LMR amount of $1,235,829. Up to March 31, 2017, CSRI has been assessed by the BCOGC additional cash deposit LMR amounts totaling $432,391, bringing the total LMR amount to $1,668,220. The total assessed LMR amount of $1,668,220 as at March 31, 2017 is secured by cash deposits. Since these cash deposits are held against future abandonment and reclamation liabilities, the balance is therefore considered by management to be restricted in its use and is classified as a non-current asset.

General and Administrative Expenses

	Three months ended March 31, 2017	2016
Consulting fees	$ **8,939**	$ 15,325
Salaries and benefits	**177,164**	185,150
Other general and administrative	**98,267**	97,527
	284,370	298,002
Capitalized portion of general and administrative expenses	**(72,796)**	(73,052)
	211,574	224,950
Share-based compensation	**11,895**	100,409
Capitalized portion of share-based compensation	**(3,509)**	(27,068)
	8,386	73,341
	$ **219,960**	$ 298,291

Consulting fees for the three months ended March 31, 2017 and 2016 are comprised of computer network maintenance fees, software technical support, land administration fees, economic analysis project work, geological consulting services and investor consulting fees.

Salaries and benefits, before capitalization, for the three months ended March 31, 2017 have decreased by $7,986 or 4.3% compared with the three months ended March 31, 2016 due to a reduction in temporary administrative staffing requirements.

The Corporation capitalizes, within both Exploration and Evaluation (“E&E”) assets and P,P&E, certain salary and benefit costs associated with staff directly involved in exploration and development activities. For the three month period ended March 31, 2017, the Corporation capitalized a total of $72,796 (2016: $73,052) of general and administrative expenses, including consulting fees, salaries and benefits directly related to exploration and development activities.

The granting from time to time of options to acquire common shares affects the share-based compensation expense recorded in the respective comparative periods. In the three months ended March 31, 2017 there were Nil options granted (2016: 1,600,000) to acquire common shares of the Corporation, thereby causing share-based compensation expense to decrease by $88,514 or 88.2% from first quarter 2016 to the first quarter 2017. The average price of the Corporation’s common shares on the Exchange for the three months ended March 31, 2017 was $0.15 (2016: $0.14). For the three month period ended March 31, 2017 the Corporation capitalized $3,509 (2016: $27,068) of share-based compensation expense for those employees of the Corporation directly involved in exploration and development activities.

Other General and Administrative Expenses

	Three months ended March 31,			
		2017		**2016**
Professional fees	**$**	**33,081**	$	31,982
Investor relations and filing fees		**3,499**		5,982
Directors' fees		**8,000**		8,000
Office premises and insurance		**39,296**		35,982
Office supplies and software licences		**12,112**		12,191
Staffing costs		**2,054**		3,127
Interest and other expenses		**225**		263
		98,267		97,527
Capitalized software licences		**(5,945)**		(6,599)
	$	**92,322**	$	90,928

Professional fees for the three month period ended March 31, 2017 are comprised of legal counsel fees for corporate secretary services and various other corporate and joint venture matters, as well as the quarterly portion of annual audit and reservoir engineer fee accruals for 2017. Professional services and fees for 2017 have been held at consistent levels compared to 2016.

Office premises and insurance expenses for the three months ended March 31, 2017 have increased by $3,314 or 9.2% compared with the three months ended March 31, 2016 due to an increase in insurance premiums resulting from the operator's extra expense/control of well insurance claim the Corporation settled in the third quarter 2016 as a result of the drilling of the c-69-H/94-B-1 well in the first quarter 2016.

Critical Accounting Policies

Reference should be made to the Corporation's significant accounting policies contained in note 2 to the Corporation's audited financial statements for the year ended December 31, 2016. These accounting policies may have a significant impact on the financial performance and financial position of the Corporation.

The preparation of the Corporation's financial statements requires management to use estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the financial statements, and the amounts of expenses reported during the period. Such estimates and assumptions affect the calculation of depletion and depreciation, the estimated costs associated with the decommissioning liability, the determination of the potential impairment of petroleum and natural gas properties and E&E assets, and the calculations of share-based compensation and deferred income taxes. Management re-evaluates its estimates and assumptions on an on-going basis, but actual results may differ from those estimates. The most critical accounting policies used by the Corporation upon which estimates and assumptions are required are the impairment of petroleum and natural gas properties and E&E assets, the fair value of assets and liabilities, share-based compensation, and deferred income taxes.

Fair Value of Financial Instruments

Non-derivative Financial Instruments

Non-derivative financial instruments are comprised of cash and cash equivalents, accounts receivable, restricted deposits and accounts payable and other accrued liabilities. Non-derivative financial instruments are recognized initially at fair value including, for instruments not at fair value through comprehensive loss, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash and cash equivalents are comprised of cash on hand, unrestricted term deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less. Bank overdrafts and amounts owed under lines of credit, if any, that are repayable on demand form part of the Corporation's cash management whereby management has the ability and intent to net bank overdrafts against cash, and are included as a component of cash and cash equivalents, for the purpose of the statement of cash flows.

Other non-derivative financial instruments include accounts receivable and accounts payable and other accrued liabilities. Accounts receivable are measured using the effective interest rate method, less any impairment losses. Accounts payable and other accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payable to fair value.

The Corporation has adopted the following accounting classifications for its financial assets: cash and cash equivalents and accounts receivable are classified as loans and receivables, and restricted deposits are classified as held to maturity. The Corporation has no financial assets classified as available-for-sale. Financial liabilities include accounts payable and other accrued liabilities and are classified as other financial liabilities.

Derivative Financial Instruments

The Corporation may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices, shares prices, interest rates or foreign exchange rates. These instruments are not used for trading or speculative purposes. Debt instruments such as a convertible debenture may contain an embedded derivative. Any embedded derivatives are valued at fair value at each reporting period. Transaction costs are recognized in the statement of operations when incurred. The Corporation did not enter into any derivative financial instruments during the year.

New Accounting Policies

Reference should be made to the changes in accounting policies and practices under IFRS contained in note 3 to the Corporation's audited financial statements for the year ended December 31, 2016. In addition, as of January 1, 2017, the Corporation adopted those IFRS standards disclosed therein that became effective for annual periods commencing on or after January 1, 2017. The adoption of those standards or amendments to previous standards had no impact on the amounts recorded in the unaudited interim condensed financial statements for the three months ended March 31, 2017 or on the comparative prior period. Other upcoming changes in IFRS may have a significant impact on the financial performance and financial position of the Corporation.

Share Capital

Common Shares

The Corporation has authorized share capital of an unlimited number of common shares with no par value. As at March 31, 2017, and as at the date of this report, there were 156,758,860 common shares outstanding, unchanged from December 31, 2016.

Share Purchase Warrants

As at March 31, 2017, and as at the date of this report, there were 4,783,334 share purchase warrants outstanding at a weighted average exercise price of $0.11 per share purchase warrant, with expiry dates ranging from June 27, 2017 to December 21, 2017.

Stock Options

As at March 31, 2017, and as at the date of this report, the Corporation had outstanding options to purchase 7,063,000 common shares (being 4.51% of the common shares outstanding) at a weighted average exercise price of $0.30 per common share. From March 31, 2017 until the date of this report there have been no stock options transactions.

Off-Balance Sheet Transactions

The Corporation had no off-balance sheet transactions during the three months ended March 31, 2017 or 2016.

Related Party Transactions

Transactions with related parties are recorded at exchange amounts for services provided. During the three months ended March 31, 2017 and 2016, the transactions the Corporation had with its directors, related persons or controlled entities in the normal course of business are as follows:

Until June 30, 2016, the Corporation had retained the law firm of Gowling WLG (Canada) LLP ("Gowlings") to provide CSRI with legal, director and corporate secretary services. A former partner of Gowlings, also the principal of Jeffrey E. Dyck Professional Corporation ("DyckCorp"), has been the Corporate Secretary of the Corporation since September 1, 2014, and became a director of CSRI effective May 28, 2015. Effective July 1, 2016, CSRI retained DyckCorp to provide legal, director and corporate secretary services. During the three months ended March 31, 2017, the Corporation incurred $5,313 of total fees and disbursements, including taxes, from DyckCorp. During the three months ended March 31, 2016, the Corporation incurred $17,034 of total fees and disbursements, including taxes, from Gowlings. Such fees have been recorded at amounts agreed upon by the respective parties. The Corporation expects to retain the services of both DyckCorp and Gowlings from time to time. As at March 31, 2017 an accounts payable balance of $5,313 was outstanding to DyckCorp, and an accounts payable balance of $Nil (March 31, 2016: $17,034) was outstanding to Gowlings.

Related to a private placement closed by the Corporation on January 14, 2016, an executive officer of the Corporation subscribed to 200,000 units (4.1% of the total) for gross proceeds of $40,000.

Commitments

The Corporation had no capital commitments as at March 31, 2017. During a prior period, the Corporation's office sub-lease agreement (that originally terminated on May 31, 2016) was extended to September 30, 2017. The amended sub-lease requires the Corporation to pay base annual rent of $11.00 per square foot (formerly $19.00 per square foot) plus operating costs on 3,420 square feet. The amended sub-lease can be terminated by either party with three months notice at any point throughout the remaining term.

Going Concern

The unaudited interim condensed financial statements for the three months ended March 31, 2017 have been prepared using IFRS as they apply to a going concern, which contemplates the realization of assets and settlement of liabilities in the normal course of operations as they come due. For the three months ended March 31, 2017 the Corporation has reported a net loss and comprehensive loss of $0.3 million (2016: $0.1 million) and an accumulated deficit of $80.8 million as at that date (December 31, 2016: $80.5 million). In addition to covering on-going working capital requirements and recurring negative cash flows from operating activities, the Corporation will need to secure additional funding for any future exploration and development programs. In conjunction with recent energy price fluctuations, the current natural gas market continues to experience low commodity prices due to excess supply and lack of additional international markets to sell into. These circumstances result in material uncertainties that may cast significant doubt upon the Corporation's ability to continue as a going concern, and accordingly, the appropriateness of the use of accounting principles applicable to a going concern.

In recognition of these circumstances, the Corporation raised a total of $4.6 million of equity via various non-brokered private placements from December 2015 to December 2016. Management has also undertaken steps to reduce operating costs and general administrative expenses, including but not limited to field operational efficiencies, renegotiation of its office lease terms and reductions in staffing levels. These undertakings, while significant, are not sufficient in and of themselves to enable the Corporation to fund all aspects of its forecasted operations and any future exploration and development program, and accordingly, management will need to pursue other financing alternatives to fund the Corporation so that it may continue as a going concern. The necessary financing may be secured through either the exercise of existing warrants for the purchase of common shares, the issue of new equity or debt instruments, or entering into new joint venture or farm-in arrangements. Nevertheless, there is no assurance that such initiatives would be successful.

CSRI's ability to continue as a going concern is dependent upon its ability to fund any future exploration and development programs as well as generate positive cash flows from operating activities. The unaudited interim condensed financial statements for the three months ended March 31, 2017 do not reflect any adjustments to the carrying values and classifications of assets and liabilities, or to the reported revenues and expenses that would be necessary if the Corporation were unable to realize its assets and settle its liabilities as a going concern in the normal course of operations; such adjustments could be material.

Business Risks

Productivity

A material risk facing the Corporation is the productive capability of the discovered and undiscovered shale and coalbed methane natural gas resources on the Corporation's existing land base at Farrell Creek/Altares and the Corporation's ability to extract the potential natural gas and natural gas liquids resources economically. The Corporation will continue to utilize the knowledge, experience and technology available in the service sector to improve the productivity of the resources in this natural gas and natural gas liquids basin in northeastern British Columbia.

Exploration and Development

The Corporation, along with its joint venture partner Canbriam, is exploring the resource potential of the geological formations below the base of the Cadomin/Nikanassin zone with a focus on the Montney Formation. A number of successful vertical and horizontal wells have been drilled into the Montney Formation in the vicinity of the Corporation's lands and public information is now available on a number of these wells. This has significantly reduced the exploration risk associated with the Montney Formation in the area. Exploration risk includes both determining the existence of commercial quantities of hydrocarbons and the ability to recover any potential resource economically. Recognizing the technical expertise, operating capability and financial resources needed to explore these deeper formations, the Corporation entered into a joint venture which has resulted in the exploration, development and production of its Deep Rights at Farrell Creek/Altares with the joint venture partner bearing the initial capital cost of this program.

Financial Resources and Liquidity

The Corporation's ability to continue its operations is highly dependent upon capital markets. Its ability to develop its assets and realize their carrying values is dependent upon the continued support of its shareholders and joint venture partner, favorable capital market conditions and commodity prices, obtaining additional equity financing, converting undiscovered and discovered resources into economically recoverable reserves, and ultimately, generating revenues sufficient to cover operating costs and capital requirements. Without the support of any one of these factors, or a number of them together, the Corporation's ability to continue its operations could be compromised.

To minimize financial risk, the Corporation pre-funds all capital commitments. Included in such estimated capital commitments is a minimum level of administrative and operating costs to see the Corporation through any potential disruption in the equity market and any commodity price downward cycle.

Commodity Prices

The Corporation's exploration and development efforts are targeted principally on natural gas and natural gas liquids. There exists an efficient and sophisticated market for natural gas and natural gas liquids in North America which is sensitive to factors affecting the supply of and demand for these commodities. Natural gas prices influence the Corporation's investment decisions, and the timing of its commercial natural gas production which will impact the Corporation's revenue and cash flow. The Corporation considers publicly available price forecasts for natural gas and natural gas liquids in its evaluation of investment economics and returns.

Operating Capability

The Corporation is pursuing large unconventional natural gas and natural gas liquids projects that if successful will require additional operating staff and experience to fully develop. The Corporation has a technically strong team suitable for its current operations but does not currently possess the skills and staff needed to conduct an efficient large scale development operation. To mitigate the risk inherent in assembling the necessary operating team, the Corporation has entered into a joint venture with an operator with the necessary experience and skills.

Land Acquisition and Tenure

Rights to explore for and extract hydrocarbons are generally acquired from the Crown or private parties and require certain work to be performed within a specific time period to retain such mineral rights. Mineral rights acquired from the Crown are usually obtained through a closed bid process. In order to expand its exploration activity, the Corporation must have the financial resources needed to bid on Crown mineral rights and if successful, must have the additional funds to make the required exploration expenditures. The Corporation has acquired its existing mineral rights from the Province of British Columbia and, as a result of drilling expenditures on its lands through to the date of this report, has retained these mineral rights for terms of up to ten years. The Corporation continues to use joint ventures as well as targeted drilling and development activity to reduce the risk of losing any of its mineral rights.

Environment and Public Policy

The exploration, development and production activities of the Corporation are highly regulated and the trend of public policy is to provide additional incentives and regulations to reduce the impact of industry activity on the environment. The principal component produced during production operations that would impact the environment are fracture fluids. The fracture fluids are recycled and ultimately re-injected into deep geologic formations at a commercial facility and in future, may be re-injected at Corporation-owned facilities.

Reader's Advisories

Non-GAAP/IFRS Terminology

This MD&A contains important, comparable industry benchmarks such as net working capital and operating netbacks which are not recognized measures under IFRS, referred to as Generally Accepted Accounting Principles ("GAAP"). Management believes these measures are useful for reporting purposes, but cautions readers that these measures not be considered as alternatives in accordance with GAAP.

Net working capital is defined as total current assets less total current liabilities. Operating netbacks are calculated by taking petroleum and natural gas sales, net of royalties expense (however adding back royalty credits applied to P,P&E in the financial statements as the royalties expense is a non-cash item) less operating costs from the statement of loss and comprehensive loss and dividing by production for the period.

Frequently-used Industry Terminology

The Corporation uses the following frequently recurring industry terms in this MD&A: "boe" refers to barrels of oil equivalent, "Mboe" refers to thousand barrels of oil equivalent, "GJ" refers to gigajoules,

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MANAGEMENT DISCUSSION AND ANALYSIS

For the three month period ended March 31, 2017

"Mcf" refers to thousand cubic feet, "MMcf" refers to million cubic feet, "Bcf" refers to billion cubic feet, "Tcf" refers to trillion cubic feet, "MMbtu" refers to million British thermal units, and "/d" refers to per day. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. The Corporation uses a boe conversion ratio of 6 Mcf of natural gas to 1 barrel of crude oil equivalent. 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 on a 6:1 basis may be misleading as an indication of value. The Corporation also uses a natural gas heating content conversion ratio of 1 Mcf to 1.05 GJ. These conversion ratios are based on energy equivalency conversion methods primarily applicable at the burner tip and do not necessarily represent a value equivalency at the wellhead.

Forward-looking Statements

Information provided herein contains estimates and assumptions which management is required to make regarding future events and may constitute forward-looking statements within the meaning of applicable securities laws. Management's assessment of future plans and operations, capital expenditures, methods of financing capital expenditures and the ability to fund financial liabilities, expected commodity prices and the impact on CSRI, expected increase in royalty rates, and the timing of and impact of adoption of new accounting policies under GAAP may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with natural gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risk, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of the acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources.

Although management believes the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. The use of any of the words "anticipate", "believe", "continue", "estimate", "expect", "forecast", "may", "intend", "likely", "will", "project", "plan", "should", "possible", "probable", "schedule", "position", "goal", "objective", and similar expressions are intended to identify forward-looking information. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

The risks associated with these forward-looking statements include, but are not limited to, the following:

- delays in oil and gas regulatory approvals;
- CSRI's ability to raise funds in the available equity markets;
- fluctuations in natural gas production levels; and
- volatility in market prices for natural gas.

The Corporation will endeavor to update all forward-looking statements for any material changes to the circumstances or information and estimates presented herein as feasible or as required by applicable securities laws.

Corporate Information

Additional information regarding the Corporation is available on SEDAR at www.sedar.com or the Corporation's website at www.csri.ca.