MANAGEMENT DISCUSSION AND ANALYSIS

For the three and twelve month periods ended December 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 and twelve months ended December 31, 2017 should be read in conjunction with the audited financial statements for the year ended December 31, 2017 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 April 25, 2018, the date of review and approval by the Corporation's Board of Directors.

This MD&A contains non-GAAP measures and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with the Corporation's disclosures under the heading **Reader's Advisories** located on pages 14 and 15 of this MD&A.

Corporate Overview

CSRI is a natural resources company whose shares are listed under the trading symbol 'SPI' on the TSX Venture Exchange (the "Exchange"). 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 for and developing the productive capability of the Montney Formation natural gas and natural gas liquids resource play in the Farrell Creek/Altares area of northeastern British Columbia ("NEBC"). 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			
	Q4	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average sales volumes								
- natural gas (MMcf/d)	**0.57**	0.64	0.61	0.74	1.10	-	-	0.63
Sales price (per Mcf)	**$ 0.53**	$ 0.93	$ 2.39	$ 2.48	$ 2.37	$ -	$ -	$ 1.41
Total sales volumes								
- natural gas (MMcf)	**52.3**	59.0	55.4	66.3	101.1	-	-	57.7
Natural gas sales	**$ 27**	$ 55	$ 132	$ 164	$ 240	$ -	$ -	$ 84
Operating netbacks	**$ (47)**	$ (19)	$ 37	$ 88	$ 190	$ (54)	$ (80)	$ (20)
Net cash flows from (used in) operating activities	**$ (185)**	$ (170)	$ (196)	$ (104)	$ (133)	$ 203	$ (164)	$ (407)
Net income (loss)	**$ (858)**	$ (482)	$ (348)	$ (301)	$ (29,356)	$ 111	$ (682)	$ (142)
Net income (loss) per share	**$ (0.00)**	$ (0.01)	$ (0.00)	$ (0.00)	$ (0.19)	$ 0.00	$ (0.01)	$ (0.00)
Net working capital	**$ 1,962**	$ 356	$ 732	$ 817	$ 1,156	$ 1,214	$ 1,259	$ 1,232
Total assets	**$ 46,023**	$ 44,604	$ 45,115	$ 45,021	$ 45,673	$ 74,562	$ 74,485	$ 75,649
Shareholders' capital	**$ 43,553**	$ 42,284	$ 42,623	$ 42,689	$ 42,978	$ 71,859	$ 71,727	$ 71,772
Common shares outstanding	**177,494**	159,459	159,459	156,759	156,759	152,592	152,592	146,192
Net capital expenditures	**$ 215**	$ 67	$ 294	$ 45	$ 183	$ 275	$ 391	$ 3,096

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

Average field production has remained relatively constant due to the lower decline rate associated with each of the Corporation's Montney wells being in the stable stages of their production life. Price volatility, due to excess North American natural 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 dramatically towards the end of 2015 and in early 2016. As a result, CSRI and Canbriam decided to shut-in their 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. A similar situation of price erosion began to emerge in the third quarter 2017, marked by extreme volatility in day to day natural gas pricing. It was decided to maintain production through the fourth quarter 2017 as the duration of the price swings was difficult to predict.

As at December 31, 2016, the estimated recoverable amount of the Gething Exploration and Evaluation ("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 assets for the Gething E&E assets of $29.1 million was recorded in the statement of operations in the fourth quarter 2016. The Corporation determined that there were no further indicators of impairment of E&E assets as at December 31, 2017.

Natural Gas Properties

Farrell Creek/Altares: Operational Highlights

The lack of pipeline egress for the rapidly growing natural gas production that has been discovered in the Montney Formation in NEBC has resulted in large volumes of natural gas being trapped behind the sales point at Station 2, the benchmark pricing point on the Enbridge Westcoast Energy pipeline system. As a result, natural gas producers in NEBC have experienced downward pressure on natural gas prices and unpredictable production curtailment on all pipeline systems transporting natural gas out of NEBC. Significant investment is being made on new pipeline infrastructure, including TransCanada Corporation's North Montney Mainline project as well as additional line looping by Enbridge on their Westcoast Energy Mainline system. These projects will add additional egress for natural gas producers beginning in 2019, however significant disruptions and outages resulting in extreme volatility in natural gas prices have and will continue to occur until this new pipeline capacity is available. As a result of the uncertainty in natural gas prices, the Corporation curtailed all capital spending while continuing to conduct required field activities and regulatory compliance.

CSRI's eastern block of lands is located within the liquids rich Montney Formation resource fairway. Drilling and production activity immediately north of CSRI's lands has demonstrated extremely rich condensate and natural gas liquids recoveries. On July 26, 2017, at a British Columbia Crown land sale, a land parcel comprising 5,542 hectares (13,855 acres) at West Attachie, six miles north of CSRI's lands, was purchased by a third party for $77.0 million at an average price of $13,894 per hectare ($5,558 per acre). Two West Attachie wells brought on production in the second quarter 2017 have produced a combined volume of approximately 220 Mbbls of condensate for cumulative production of approximately 370 Mboe. These wells and a newly drilled five well pad are located approximately three and one half miles northeast of CSRI's lands.

Liquified natural gas ("LNG") exports from the west coast of Canada have long been seen as a significant source of value creation for natural gas producers in NEBC. Although still speculative in nature, momentum appears to be building for an announcement of a final investment decision to move forward with at least one LNG facility. On March 22, 2018, the British Columbia government announced tax break incentives to the LNG Canada project backed by Royal Dutch Shell in partnership with PetroChina, KOGAS and Mitsubishi Corporation. The tax incentives announced include a break on carbon taxes payable, an exemption on PST relative to construction costs and the elimination of a special LNG income tax. A final investment decision by LNG Canada is expected sometime in 2018.

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 NEBC 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 NEBC.

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, 2017 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.

SUMMARY OF RESERVES AND NET PRESENT VALUE ("NPV")

AS AT DECEMBER 31, 2017

	Shale Gas (1)		**Barrels of Oil Equivalent (5)**		**NPV Discounted At 10%**
	Gross(2) (MMcf)	Net (3) (MMcf)	Gross (2) (Mboe)	Net (3) (Mboe)	(000's)
PROVED					
Developed Producing	1,550	1,506	258	251	$233
Total Proved	1,550	1,506	258	251	$233
PROBABLE	8,756	8,228	1,459	1,371	$1,520
TOTAL PROVED PLUS PROBABLE (4)	**10,306**	**9,734**	**1,718**	**1,622**	**$1,753**

Notes:

(1) "Shale Gas" means natural gas contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily absorbed on the kerogen or clay minerals, and that usually requires the use of hydraulic fracturing to achieve economic production rates.
(2) "Gross Reserves" are CSRI's working interest share of the remaining reserves, before deduction of royalties.
(3) "Net Reserves" are CSRI's working interest share of remaining reserves less all Crown royalties.
(4) May not add due to rounding.
(5) Barrel of oil equivalent ("boe") amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 "bbl").

Montney Formation Resource Assessment

In the prior period, GLJ was also engaged to prepare an independent resource assessment of the Montney Formation on the Corporation's Farrell Creek/ Altares lands in NEBC 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 December 31,		Twelve months ended December 31,	
	2017	**2016**	**2017**	**2016**
Total sales volumes of natural gas (Mcf)	**52,305**	101,141	**232,970**	158,877
Average sales volumes of natural gas (1)				
Mcf/d	**568**	1,098	**639**	433 (1)
boe/d	**95**	183	**106**	72 (1)
Total natural gas sales ($)	**$ 27,495**	$ 240,136	**$ 378,912**	$ 324,114
Average sales price of natural gas				
$/Mcf	**$ 0.53**	$ 2.37	**$ 1.63**	$ 2.04
$/boe	**$ 3.15**	$ 14.25	**$ 9.76**	$ 12.24

Note:

(1) Given that there was no production during the second or third quarters of 2016, the 2016 annual daily volumes represent six months of active production reported over a twelve month period.

Total production volumes in 2017 increased compared to 2016 due to the restart of production that was shut-in during the middle part of 2016 and increased initial flush production from the wells that had been shut-in.

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 $2.8 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 current rates of production, the Corporation does not expect to remit any crown royalties to the government of British Columbia 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 (non-GAAP measure)

During the three months ended December 31, 2017, the Corporation applied $114 (2016: $3,318) of royalty credits against crown royalties that would otherwise have been payable:

For the three months ended December 31, 2017					$/Mcf		$/boe
Natural gas sales	**$**	**27,495**		**$**	**0.53**	**$**	**3.15**
Royalties expense		**(114)**	***0.4%***		**(0.00)**		**(0.01)**
Net revenue		**27,381**			**0.53**		**3.14**
Royalty credits applied		**114**			**0.00**		**0.01**
Operating costs		**(74,603)**			**(1.43)**		**(8.56)**
Operating netbacks	**$**	**(47,108)**		**$**	**(0.90)**	**$**	**(5.41)**

For the three months ended December 31, 2016					$/Mcf		$/boe
Natural gas sales	$	240,136		$	2.37	$	14.25
Royalties expense		(3,318)	*1.4%*		(0.03)		(0.20)
Net revenue		236,818			2.34		14.05
Royalty credits applied		3,318			0.03		0.20
Operating costs		(49,692)			(0.49)		(2.95)
Operating netbacks	$	190,444		$	1.88	$	11.30

During the twelve months ended December 31, 2017, the Corporation applied $9,857 (2016: $3,850) of royalty credits against crown royalties that otherwise would have been payable:

For the twelve months ended December 31, 2017					$/Mcf		$/boe
Natural gas sales	**$**	**378,912**		**$**	**1.63**	**$**	**9.76**
Royalties expense		**(9,857)**	***2.6%***		**(0.04)**		**(0.25)**
Net revenue		**369,055**			**1.59**		**9.51**
Royalty credits applied		**9,857**			**0.04**		**0.25**
Operating costs		**(319,724)**			**(1.37)**		**(8.23)**
Operating netbacks	**$**	**59,188**		**$**	**0.26**	**$**	**1.53**

For the twelve months ended December 31, 2016					$/Mcf		$/boe
Natural gas sales	$	324,114		$	2.04	$	12.24
Royalties expense		(3,850)	*1.2%*		(0.02)		(0.15)
Net revenue		320,264			2.02		12.09
Royalty credits applied		3,850			0.02		0.15
Operating costs		(287,174)			(1.81)		(10.84)
Operating netbacks	$	36,940		$	0.23	$	1.40

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 Enbridge Westcoast Energy Station 2 and the British Columbia provincial carbon taxes.

Operating costs, while remaining relatively constant on an overall basis, have decreased on a per Mcf basis from 2016 to 2017, as the annual table for ***Operating Netbacks (non-GAAP measure)*** on page 5 show. The decrease is a result of the wells being shut-in for approximately six months during the middle part of 2016, 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 and twelve month periods ended December 31, 2017 of $57,606 and $272,386, respectively, (2016: $124,614 and $191,201, respectively) equates to $1.10 and $1.17 per Mcf, respectively, (2016: $1.23 and $1.20 per Mcf, respectively). The increase in depletion for the respective twelve month periods on a gross basis is due principally to the increase in production (see ***Natural Gas Production and Revenues*** on page 4).

Liquidity and Capital Resources

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

	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Lease acquisitions and retentions	**$ 19,280**	$ 27,406	**$ 132,177**	$ 153,496
Geological and geophysical	**-**	1,266	**-**	15,416
Net expenditure on drilling, completion and facilities costs	**54,099**	291,353	**273,694**	3,426,629
Other capitalized amounts	**141,761**	(137,486)	**214,648**	349,432
Total net capital expenditures	**$ 215,140**	$ 182,539	**$ 620,519**	$ 3,944,973

From time to time, certain land leases expire thus eliminating the future economic benefits related to such leases. For the three and twelve months ended December 31, 2017, the Corporation expensed a total of $331,500 and $331,500, respectively, (2016: $Nil and $255,500, respectively) of land lease costs as exploration and evaluation expense.

For the three and twelve month periods ended December 31, 2017, net capital expenditures totaled $0.2 million and $0.6 million, respectively, (2016: $0.2 million and $3.9 million, respectively), compared to an allocated budgeted capital expenditure of $0.2 million and $0.6 million, respectively, (2016: $0.2 million and $3.6 million, respectively). For the twelve months ended December 31, 2016, the main component of the drilling, completion and facilities total of $3.4 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 in the first quarter 2016.

On August 26, 2016, the Corporation agreed to a proof of loss settlement of an operator's extra expense/well control insurance claim for the c-69-H/94-B-1 well previously drilled in the first quarter 2016 for an amount of $425,000. The settlement proceeds were received on September 21, 2016. Together, the settlement and subsequent receipt of the insurance proceeds were considered a separate economic event from the drilling of the well, and were 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.

As at December 31, 2017, the Corporation had a net working capital ***(non-GAAP measure)*** balance of $2.0 million consisting of cash in the amount of $2.1 million and receivables and prepaids of $0.2 million, offset by payables of $0.3 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 2018 of $0.8 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 2018 to total $1.0 million (a reduction of 11.7% from 2017 budgeted expenses) before capitalization of exploration and development related overhead, and has budgeted for operating netbacks ***(non-GAAP measure)*** from the Farrell Creek/Altares Montney operations for 2018 of $0.1 million (2017: $0.2 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. During the year ended December 31, 2017, CSRI was assessed by the BCOGC an additional cash deposit LMR amount of $81,200 (periods up to December 31, 2016: $432,391). The total assessed LMR amount of $1,749,420 as at December 31, 2017 (December 31, 2016: $1,668,220) is secured by cash deposits. Since these cash deposits are held against future abandonment and reclamation liabilities, the balance is considered by management to be restricted in use and is therefore classified as a non-current asset.

General and Administrative Expenses

	Three months ended December 31,		Twelve months ended December 31,	
	2017	**2016**	**2017**	**2016**
Consulting fees	$ **17,273**	$ 3,376	$ **46,892**	$ 40,089
Salaries, incentives and benefits	**183,825**	165,980	**677,567**	673,513
Other general and administrative	**89,162**	99,357	**404,499**	423,713
	290,260	268,713	**1,128,958**	1,137,315
Capitalized portion of general and administrative expenses	**(65,293)**	(92,291)	**(272,523)**	(300,068)
	224,967	176,422	**856,435**	837,247
Share-based compensation	**25,668**	20,208	**197,729**	181,042
Capitalized portion of share-based compensation	**(8,297)**	(6,299)	**(45,613)**	(53,404)
	17,371	13,909	**152,116**	127,638
	$ **242,338**	$ 190,331	$ **1,008,551**	$ 964,885

Consulting fees for the three and twelve months ended December 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 twelve months ended December 31, 2017 have remained relatively constant as compared with the twelve months ended December 31, 2016 due to a reduction in temporary administrative staffing requirements, but offset by the accrual of a short term incentive bonus amount to the Corporation's executive officers in the fourth quarter 2017.

The Corporation capitalizes, within both 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 and twelve month periods ended December 31, 2017, the Corporation capitalized a total of $65,293 and $272,523, respectively, (2016: $92,291 and $300,068, respectively) 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 twelve months ended December 31, 2017 there were options granted to acquire 2,075,000 (2016: 1,600,000) common shares of the Corporation, thereby causing share-based compensation expense, before capitalization, to increase annually by $16,687 or 9.2% from $181,042 in 2016 to $197,729 in 2017. The average price of the Corporation's common shares on the Exchange for the year ended December 31, 2017 was $0.13 (2016: $0.12). For the three and twelve month periods ended December 31, 2017 the Corporation capitalized $8,297 and $45,613, respectively, (2016: $6,299 and $53,404 respectively) 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 December 31,		Twelve months ended December 31,	
	2017	**2016**	**2017**	**2016**
Professional fees	$ **21,916**	$ 24,270	$ **117,510**	$ 124,597
Investor relations and filing fees	**6,178**	8,494	**39,439**	44,932
Directors' fees	**12,000**	8,000	**40,000**	32,000
Office premises and insurance	**28,315**	37,783	**142,576**	145,980
Office supplies and software licences	**12,411**	14,925	**46,972**	55,596
Staffing costs	**8,150**	5,701	**16,805**	19,631
Interest and other expenses	**192**	184	**1,197**	977
	89,162	99,357	**404,499**	423,713
Capitalized software licences	**(5,945)**	(6,599)	**(23,781)**	(26,397)
	$ **83,217**	$ 92,758	$ **380,718**	$ 397,316

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

Directors' fees have increased in 2017 compared to 2016 due to the appointment of an additional non-executive director effective August 22, 2017 (see news release dated August 23, 2017).

Office premises and insurance expenses for the twelve months ended December 31, 2017 have decreased by $3,404 or 2.3% compared with the twelve months ended December 31, 2016 due a reduction in office rent resulting from renegotiated lease terms effective as of the end of September 2017 (see **Commitments** on page 12).

Interest and other expenses are comprised of bank charges and interest, as well as advertising, promotional costs and charitable contributions, if any.

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, 2017. 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 and other accrued receivables, 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 other accrued receivables and accounts payable and other accrued liabilities. Accounts receivable and other accrued receivables 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 IFRS accounting classifications for its financial assets: cash and cash equivalents and accounts receivable and other accrued receivables 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. 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, 2017. In addition, as of January 1, 2018, the Corporation adopted those IFRS standards disclosed therein that became effective for annual periods commencing on or after January 1, 2018. The adoption of those standards or amendments to previous standards had no material impact on the amounts recorded in the audited financial statements for the twelve months ended December 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 December 31, 2017, there were 177,494,004 common shares outstanding. The Corporation has closed the following share issuances since December 2015:

On December 11, 2015, the Corporation closed a private placement of 12,500,000 flow-through shares at a price of $0.20 per share. The $2,500,000 of total gross proceeds from the flow-through shares private placement was allocated between common shares of $2,125,000 (calculated at the closing market price of $0.17 on the Exchange on the trading day prior to the announcement of the private placement) and a flow-through shares premium liability of $375,000, and was fully expended on eligible exploration costs in the first quarter 2016. The $375,000 of flow-through shares premium liability was reversed in the period when the expenditures were incurred and offset by the recording of an equivalent flow-through share premium income amount in the first quarter 2016.

On January 14, 2016, the Corporation closed a non-brokered private placement of 4,825,000 units at a price of $0.20 per unit for total gross proceeds of $965,000. Each unit consisted of one common share of the Corporation and one half of one share purchase warrant. Each whole share purchase warrant entitled the holder to purchase an additional common share of the Corporation for a period of one year at an exercise price of $0.25 per common share. The units were valued using the residual method calculated at the market price on the Exchange on the trading day prior to closing of $0.17 per common share under which the Corporation assigned a total value of $820,250 of the unit proceeds to the common shares, with the remaining $144,750 of the unit proceeds assigned to the share purchase warrants. Share issue costs of $38,176 were incurred in relation to the issuance of the units.

In June 2016, the Corporation closed a non-brokered private placement consisting of 1,000,000 flow-through shares at a price of $0.10 per share and 5,400,000 units at a price of $0.10 per unit for combined total gross proceeds of $640,000. The flow-through shares portion of the private placement closed on June 1, 2016 and entitled the holder to certain income tax benefits in the form of Canadian Exploration Expense. The $100,000 of total gross proceeds from the flow-through shares portion of the private placement was allocated between common shares of $85,000 (calculated at the closing market price of $0.085 on the Exchange on the trading day prior to the announcement of the private placement) and a flow-through shares premium liability of $15,000, and was fully expended on eligible exploration costs in the third quarter 2016. Therefore, the flow-through shares premium liability was reversed in the third quarter 2016 and offset by the recording of an equivalent flow-through share premium income amount. The related resource expenditure deductions were renounced to investors effective December 31, 2016. On June 27, 2016, the Corporation closed the unit portion of the private placement for total gross proceeds of $540,000. Each unit consisted of one common share of the Corporation and one half of one share purchase warrant. Each whole share purchase warrant entitled the holder to purchase an additional common share of the Corporation for a period of one year at an exercise price of $0.10 per common share. The units were valued using the residual method calculated at the closing market price on the

Exchange on the trading day prior to the announcement of the private placement of $0.085 per common share, under which the Corporation assigned a total value of $459,000 of the unit proceeds to the common shares, with the remaining $81,000 of the unit proceeds assigned to the share purchase warrants. Share issue costs of $27,046 were incurred in relation to the above combined issuance of flow-through shares and units.

On December 21, 2016, the Corporation closed a non-brokered private placement of 4,166,668 units at a price of $0.12 per unit for total gross proceeds of $500,000. Each unit consisted of one common share of the Corporation and one half of one share purchase warrant. Each whole share purchase warrant entitled the holder to purchase an additional common share of the Corporation for a period of one year at an exercise price of $0.12 per common share. The units were valued using the residual method calculated at the closing market price on the Exchange on the trading day prior to the announcement of the private placement of $0.11 per common share, under which the Corporation assigned a total value of $458,334 of the unit proceeds to the common shares, with the remaining $41,666 of the unit proceeds assigned to the share purchase warrants. Share issue costs of $45,029 were incurred in relation to the issuance of the units.

The Corporation closed, effective November 17, 2017, a rights offering equity financing (the "Rights Offering"). The Rights Offering issued rights to holders of the Corporation's common shares at the close of business on the record date of October 27, 2017 on the basis of one right for each common share held. Each nine and one-half rights entitled the holder to subscribe for one common share of CSRI upon payment of the subscription price of $0.12 per common share prior to the expiry date of November 14, 2017. The Rights Offering was fully subscribed and subsequently 16,785,143 common shares were issued resulting in total gross proceeds to the Corporation of $2,014,217. Share issue costs of $68,186 were incurred in relation to the Rights Offering.

Share Purchase Warrants

During the twelve months ended December 31, 2017, 3,245,833 (2016: 2,555,000) share purchase warrants expired and 3,950,001 (2016: Nil) share purchase options were exercised. As at December 31, 2017, and as at the date of this report, there were Nil share purchase warrants outstanding.

Stock Options

During the twelve months ended December 31, 2017, 2,790,000 (2016: 267,000) stock options were forfeited or expired and 2,075,000 (2016: 1,600,000) stock options were granted. As at December 31, 2017, and as at the date of this report, the Corporation had outstanding options to purchase 7,048,000 common shares (being 4.0% of the common shares outstanding) at a weighted average exercise price of $0.23 per common share.

Off-Balance Sheet Transactions

The Corporation had no off-balance sheet transactions during the three and twelve month periods ended December 31, 2017 or 2016.

Related Party Transactions

Transactions with related parties are recorded at exchange amounts for services provided. During the twelve months ended December 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 twelve months ended December 31, 2017, the Corporation incurred $44,800 (six months ended December 31, 2016: $20,039) of total fees and disbursements, including taxes, from DyckCorp. Such fees have been recorded at amounts agreed upon by the respective parties. The Corporation expects to retain the services of both DyckCorp and other outside law firms from time to time. As at December 31, 2017 an accounts payable balance of $20,039 (December 31, 2016: $11,540) was outstanding to DyckCorp.

Under the private placement closed by the Corporation on December 11, 2015 (see ***Common Shares*** on page 10), a non-executive director and an executive officer of the Corporation subscribed to a total of 1,035,000 flow-through shares (8.3% of the total) for gross proceeds of $207,000. Under the private placement closed by the Corporation on January 14, 2016 (see ***Common Shares*** on page 10), an executive officer of the Corporation subscribed to 200,000 units (4.1% of the total) for gross proceeds of $40,000. Under the unit portion of the private placement closed by the Corporation on June 27, 2016 (see ***Common Shares*** on page 10) an executive officer of the Corporation subscribed to 200,000 units (3.7% of the total) for gross proceeds of $20,000. Under the private placement closed by the Corporation on December 21, 2016 (see ***Common Shares*** on page 11), directors and executive officers of the Corporation subscribed to a total of 625,002 units (15.0% of the total) for total gross proceeds of $75,000. Under the Rights Offering closed by the Corporation on November 17, 2017 (see ***Common Shares*** on page 11), directors, executive officers and insiders of the Corporation subscribed to a total of 13,808,022 common shares (82.3% of the total) for total gross proceeds of $1,656,963.

Executive compensation for the year ended December 31, 2017 consists of amounts paid to or earned by executive officers, including incentives and benefits, of $618,138 (2016: $592,807) as well as fees paid to non-executive directors of $40,000 (2016: $32,000).

Commitments

The Corporation had no capital commitments as at December 31, 2017. The Corporation's office sub-lease agreement (that originally terminated on May 31, 2016) was extended to September 30, 2017 during a prior period. The amended sub-lease required 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 until September 30, 2017. In June 2017, the sub-lease agreement was amended a second time on a month-to-month term basis beyond September 30, 2017 at a base annual rent of $Nil per square foot plus operating costs.

Going Concern

The audited financial statements for the year ended December 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 year ended December 31, 2017 the Corporation has reported a net loss and comprehensive loss of $2.0 million (2016: $30.0 million, including a $29.1 million impairment of natural gas assets) and an accumulated deficit of $82.5 million as at that date (December 31, 2016: $80.5 million). In addition to covering on-going net working capital ***(non-GAAP measure)*** requirements and recurring negative cash flows used in 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 $2.4 million of equity in 2017 via a rights offering (see **Share Capital** on pages 10 and 11) and the exercise of share purchase warrants. Management has also undertaken steps to reduce operating costs and general and administrative expenses, including but not limited to, field operational efficiencies, renegotiation of its office lease terms, and reductions in staffing levels/remuneration. 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 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 audited financial statements for the year ended December 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 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 NEBC.

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 natural gas and natural gas liquids resource plays 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, which management feels is a useful supplementary measure of the liquidity of the Corporation. 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 operations and dividing by production for the period. Management feels that operating netbacks are a key industry benchmark and a measure of performance of the Corporation that provides investors/readers with information that is commonly used by other petroleum and natural gas producers.

Canadian Spirit Resources Inc.

MANAGEMENT DISCUSSION AND ANALYSIS

For the three and twelve month periods ended December 31, 2017

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, "Mbbls" refers to thousands of barrels, "GJ" refers to gigajoules, "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.