CANADIAN SPIRIT RESOURCES INC.

FORM 51-101F1
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

PART 1 RELEVANT DATES

Item 1.1 Date of Statement and Statement Information

This Statement of Reserves Data and other Oil and Gas Information for Canadian Spirit Resources Inc. ("CSRI" or the "Corporation") is dated April 21, 2015. The effective date of the information provided in this statement is December 31, 2014 unless otherwise indicated. The information was prepared between December 31, 2014 and April 21, 2015.

PART 2 DISCLOSURE OF RESERVES DATA

GLJ Petroleum Consultants Ltd. ("GLJ") was engaged to prepare an independent reserve assessment on the Corporation's lands as at December 31, 2014 in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("GLJ Reserve Report").

The GLJ Reserve Report also presents the estimated net present value of future net revenue before taxes, at various discount rates. Assumptions and qualifications relating to costs and prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by CSRI which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by GLJ in preparing the GLJ Reserve Report and were accepted as represented without independent verification. In the absence of such information, GLJ relied, with the approval of CSRI, upon its opinion of reasonable practice in the industry. All information provided to GLJ was as at December 31, 2014 and accordingly, certain of such information may not be representative of current conditions.

The definitions of the various categories of reserves and expenditures are those set out in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the escalating price and cost assumptions contained in the GLJ Reserve Report will be attained and variances could be material. The reserve and revenue estimates set forth below are estimates only and the actual reserves and realized revenue may be greater or less than those calculated.

Item 2.1 Reserves Data – Forecast Prices and Costs

The following table discloses the Corporation's gross and net proved reserves and proved plus probable reserves, estimated using forecast prices and costs.

Table 2.1.1
SUMMARY OF RESERVES AS AT DECEMBER 31, 2014
(Forecast Prices & Costs) (4)

	Natural Gas (1)		Barrels of Oil Equivalent	
	Gross (2) (MMcf)	Net (3) (MMcf)	Gross (2) (Mboe)	Net (3) (Mboe)
PROVED				
Developed Producing	2,150	2,086	358	348
Total Proved	2,150	2,086	358	348
PROBABLE	8,923	8,422	1,487	1,404
TOTAL PROVED PLUS PROBABLE	11,073	10,508	1,845	1,751

Notes:
(1) Estimates of Reserves of natural gas include associated gas and non-associated gas.
(2) "Gross Reserves" are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.
(3) "Net Reserves" are the Corporation's working interest share of remaining reserves less all Crown royalties.
(4) May not add due to rounding.

The following table summarizes the net present value of the Corporation's reserves based on the GLJ future price forecast as at December 31, 2014.

Table 2.1.2
SUMMARY OF NET PRESENT VALUES AS AT DECEMBER 31, 2014

	Discounted at				
($ Thousands) (1)	0%	5%	10%	15%	20%
PROVED					
Developed Producing	2,190	1,860	1,566	1,333	1,154
Total Proved	2,190	1,860	1,566	1,333	1,154
PROBABLE	19,975	8,905	4,091	1,806	652
TOTAL PROVED PLUS PROBABLE	22,165	10,765	5,657	3,139	1,806

Note:
(1) May not add due to rounding.

The following two tables provide additional information regarding the future net revenue attributable to total proved reserves and total proved plus probable reserves.

Table 2.1.3 discloses, in the aggregate, certain elements of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount. All properties are located in Canada.

Table 2.1.3
TOTAL FUTURE NET REVENUE (Undiscounted)
AS AT DECEMBER 31, 2014
(Forecast Prices & Costs) ($ Thousands)

RESERVE CATEGORY	Sales Revenue	Royalties	Operating Costs	Total Develop-ment Costs	Well Abandon-ment Costs	BT Future Net Revenue (1) (2)
PROVED	9,843	295	6,859	367	131	2,190
PROVED PLUS PROBABLE	62,479	3,445	22,925	13,612	333	22,165

Notes:
(1) BT = Before Taxes.
(2) May not add due to rounding.

Table 2.1.4 discloses, by production group, the net present value of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

Table 2.1.4
NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP AS AT DECEMBER 31, 2014
(Forecast Prices & Costs)

RESERVE CATEGORY	PRODUCTION GROUP	Future Net Revenue BT Discounted (10%/Yr.) $ Thousands (1)	Unit Value BT Discounted (10%/Yr.) $/boe (1) (2)
PROVED	Natural Gas	1,566	4.50
PROVED PLUS PROBABLE	Natural Gas	5,657	3.23

Notes:
(1) BT = Before Taxes.
(2) Calculated as the Net Present Value before income taxes discounted at 10% per year divided by the net reserves volume.

PART 3 PRICING ASSUMPTIONS

Item 3.1 Forecast Prices used in Estimates

The forecast reference prices used by GLJ in preparing the Corporation's reserves data are provided in the table below.

Table 3.1.1
SUMMARY OF PRICING, INFLATION RATE AND EXCHANGE RATE ASSUMPTIONS AS AT DECEMBER 31, 2014

FORECAST YEAR	WTI CUSHING OKLAHOMA ($US/bbl)	HENRY HUB ($US/MMBtu)	B.C. WESTCOAST STATION 2 ($Cdn/MMBtu)	INFLATION RATE (%/Yr.)	EXCHANGE RATE ($US/$Cdn.)
2015	62.50	3.31	3.16	2	0.85
2016	75.00	3.75	3.62	2	0.875
2017	80.00	4.00	3.87	2	0.875
2018	85.00	4.25	4.12	2	0.875
2019	90.00	4.50	4.38	2	0.875
2020	95.00	4.75	4.63	2	0.875
2021	98.54	5.00	4.88	2	0.875
2022	100.51	5.25	5.13	2	0.875
2023	102.52	5.50	5.38	2	0.875

Escalation rate of 2.0% thereafter

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The GLJ Reserve Report represents the Corporation's reserves data as at December 31, 2014. The reconciliation of changes in reserves is based on the previous year end occurring as at December 31, 2013.

Table 4.1.1
RECONCILIATION OF COMPANY GROSS RESERVES

FACTORS	Conventional Natural Gas			BOE		
	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2013	2,582	8,578	11,160	430	1,430	1,860
Discoveries	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0
Technical Revisions	(92)	411	318	(15)	68	53
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	(66)	(66)	0	(11)	(11)
Production	(340)	0	(340)	(57)	0	(57)
December 31, 2014	2,150	8,923	11,073	358	1,487	1,845

* The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

The following table disclosed the Corporation's gross proved and probable undeveloped reserves in which the Corporation has a working interest position. All proved undeveloped reserves are attributable to acreage that offsets existing production and are determined as per NI 51-101 guidelines. The Corporation has plans for developing most of the proved undeveloped and the probable undeveloped reserves within the next five years, in order to allow for appropriate activity levels and to increase the likelihood of bringing new wells on production in a projected higher gas price environment.

Table 5.1.1
UNDEVELOPED RESERVES ATTRIBUTED IN CURRENT YEAR

PROVED UNDEVELOPED RESERVES

Conventional Natural Gas (MMcf)		BOE (MMbl)	
Attributed This Year	Current Total	Attributed This Year	Current Total
0	0	0	0

PROBABLE UNDEVELOPED RESERVES

Conventional Natural Gas (MMcf)		BOE (MMbl)	
Attributed This Year	Current Total	Attributed This Year	Current Total
0	8,327	0	1,388

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

Estimates of economically recoverable oil and natural gas reserves and the associated future net cash flows are based upon a number of variable factors and assumptions. The main area of uncertainty is commodity prices, as the Corporation currently sells all production at spot market pricing and has no hedges presently in place.

The process of estimating oil and gas reserves is complex, requiring significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas processing and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions, and are evaluated by an independent engineering firm. As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in period end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. The reserve estimates of the Corporation's oil and natural gas reserves produced in this document are estimates only. There is no assurance or guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein.

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Corporation's reserves.

Table 5.3.1
FUTURE DEVELOPMENT COSTS
(Forecast Prices & Costs) ($ Thousands) (1) (2)

Year	For Proved Reserves	For Proved Plus Probable Reserves
2015	0	0
2016	0	0
2017	0	0
2018	212	212
2019	0	13,245
THEREAFTER	155	155
TOTAL UNDISCOUNTED	367	13,612

Notes:
(1) Future Development Costs shown are associated with booked reserves in the GLJ Reserve Report and do not necessarily represent the Corporation's full exploration and development budget.
(2) May not add due to rounding.

The Corporation expects that the funds required for future development costs will be obtained from the combination of positive working capital, internally-generated cash flow, credit facilities and equity financing. There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the GLJ Reserve Report. Failure to develop those reserves would have a negative impact on future cash flow.

Interest and other costs of external funding are not included in the future development costs of the reserves or in the future net revenue estimates, and would reduce reserves and future net revenue to some degree depending upon the funding source utilized. The Corporation does not anticipate that interest or other funding costs would make development of any property uneconomic.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

CSRI's core area of activity is in the Farrell Creek/Altares area of northeastern British Columbia approximately 15 km north of the town of Hudson's Hope.

The Corporation has focused on two primary objectives in this core area:

- The Cretaceous Gething Formation coals and tight sands
- The Triassic Montney Formation shale gas

a) Gething

The Gething coals and tight sand pilot project resulted in the drilling of 14 wells including 13 potential producing wells and one water disposal well. Seven wells were completed, equipped and tied into the 100% owned CSRI gas plant. The plant has an initial processing capacity of 1.25 MMcf/day of natural gas and is pipeline connected to the Spectra Energy mainline. The pilot project was suspended in 2010 and the producing wells and gas plant are currently shut in. Of the remaining seven wells that were drilled, six are cased and suspended and one has been abandoned. No reserves have been attributed to the Gething project.

b) Montney

The Montney shale gas project has 12 wells drilled with 10 (net 3.25) drilled on joint venture ("JV") lands and two on 100% CSRI lands. Five JV wells are currently on production through the joint venture gas plant (CSRI 35%) that is pipeline connected to the Spectra Energy mainline. The JV plant has a processing capacity of 10 MMcf/day of natural gas. Of the remaining nine wells that were drilled, eight are cased and suspended and one has been abandoned.

Item 6.2 Properties with No Attributed Reserves

The Corporation's unproved properties are comprised of 18,182 gross (10,265 net) hectares of Montney Formation rights and 14,641 gross (14,510 net) hectares of Gething Formation rights located in British Columbia, Canada, none of which have any work commitments.

The presence of economic quantities of hydrocarbons on lands with no attributed reserves is uncertain until drilled and tested. Beyond the need to drill and test exploration areas, additional factors may influence the Corporation's ability to develop these lands, including escalation of capital costs and operating costs, the potential requirement to expand existing infrastructure and a material drop in commodities prices.

Item 6.3 Forward Contracts

As at December 31, 2014, the Corporation had not entered into any forward contracts, transportation agreements or other future obligations.

Item 6.4 Additional Information Concerning Abandonment and Restoration Costs

Table 6.4.1
ABANDONMENT & RECLAMATION COSTS (1)
(Forecast Prices & Costs) ($ Thousands)

	Total Proved		Total Proved Plus Probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
	131	31	333	24

Note:
(1) The Corporation has taken abandonment costs from the GLJ Reserve Report for wells that have reserves.

For purposes of the audited financial statements, as at December 31, 2014 the Corporation estimated the total future asset retirement obligations to be $2.2 million. The total future asset retirement obligation ("ARO") was estimated based on the Corporation's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities, the estimated rate of inflation, and the estimated timing of the costs to be incurred in future periods.

Well abandonment estimates are based upon individual well characteristics and location, and lease reclamation estimates are based on geographic location.

Table 6.4.2
ASSET RETIREMENT OBLIGATIONS ("ARO")

	ARO Undiscounted ($ Thousands)	ARO discounted at 10% ($ Thousands)	Estimated net ARO expected to be paid in the next 3 years ($ Thousands)	Estimated Number of net wells for which costs are expected to be incurred
	3,288	666	-	19.25

Item 6.5 Tax Horizon

Based on after tax economic forecasts prepared by GLJ, income taxes are not payable by the Corporation.

Item 6.6 Costs Incurred

During 2014, the Corporation incurred $0.2 million of acquisition and retention costs for unproved properties and $9.5 million (net) of exploration and development costs in western Canada.

Item 6.7 Exploration and Development Activities

During 2014, the Corporation drilled two operated exploration wells on its 100% lands. One well at 1-1-83-25W6 was drilled and abandoned and the other at C-081-H/094-B-01 was cased and is awaiting completion.

For the year ended December 31, 2014, gross capital expenditures (net of British Columbia government incentive Summer Drilling and Deep Royalty Credits earned) totaled $10.1 million (2013: $1.3 million), compared to a budgeted capital expenditure of $9.7 million (2013: $1.4 million).

The Corporation's capital budget is approved on an annual basis, and subsequently reviewed quarterly, by the Board of Directors. The Board of Directors has approved a capital expenditure budget for 2015 of up to $13.4 million (net), subject to financing, primarily towards the fracture stimulation and tie-in of the C-081-H/094-B-01 horizontal well planned for the third quarter 2015 and the drilling of an exploration well on the western lands, and includes an estimated $0.3 million for capitalized overhead.

CSRI has budgeted for cash administration expenses (general and administrative expenses excluding share-based compensation) for 2015 to total $1.3 million (2014: $1.5 million), before capitalization of exploration and development related overhead, and has budgeted for operating netbacks from the Farrell Creek Montney operations for 2015 of $1.5 million (2014: revised budget of $0.9 million).

Item 6.8 Production Estimates

The following table summarizes the Corporation's estimated future average daily production volumes for 2015.

Table 6.8.1
SUMMARY OF FIRST YEAR PRODUCTION AND OIL AND GAS RESERVES

	2015 Average Daily Production		Reserves			
	Natural Gas		Natural Gas		Oil Equivalent	
	Company Gross (Mcf/d)	Company Net (Mcf/d)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mboe)	Company Net (Mboe)
Proved Producing	768	745	2,150	2,086	358	348
Proved Developed Nonproducing	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0
Total Proved	768	745	2,150	2,086	358	348
Total Probable	12	11	8,923	8,422	1,487	1,404
Total Proved Plus Probable	780	757	11,073	10,508	1,845	1,751

Item 6.9 Production History

The following table summarizes the Corporation's average gross daily production volumes for the financial year ended December 31, 2014.

Table 6.9.1
PRODUCTION HISTORY YEAR ENDED DECEMBER 31, 2014

Natural Gas (MMcf/d)		Average Per Unit of Volume ($/Mcf) Production			
Yearly Quarter	Production Volume (1)	Price	Royalties (2)	Costs (3)	Netbacks
1st Quarter	1.05	5.18	0.59	1.04	4.14
2nd Quarter	0.95	4.40	0.97	2.09	2.31
3rd Quarter	0.91	3.7	0.68	1.85	1.85
4th Quarter	0.81	3.17	0.52	1.08	2.09

Notes:

(1) Production volumes reflect the Corporation's share of average daily production volume, before deduction of royalties.
(2) Royalties exclude prior period adjustments and credits.
(3) Production costs include transportation costs and production operating costs.