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 25, 2014. The effective date of the information provided in this statement is December 31, 2013 unless otherwise indicated. The information was prepared between December 31, 2013 and April 25, 2014.

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, 2013 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, 2013 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, 2013
(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	2,582	2,493	430	416
Total Proved	2,582	2,493	430	416
PROBABLE	8,578	8,106	1,430	1,351
TOTAL PROVED PLUS PROBABLE	11,160	10,599	1,860	1,767

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, 2013.

Table 2.1.2
SUMMARY OF NET PRESENT VALUES AS AT DECEMBER 31, 2013

	Discounted at				
($ Thousands) (1)	0%	5%	10%	15%	20%
PROVED					
Developed Producing	5,421	4,417	3,708	3,190	2,799
Total Proved	5,421	4,417	3,708	3,190	2,799
PROBABLE	17,868	7,511	3,171	1,104	42
TOTAL PROVED PLUS PROBABLE	23,289	11,928	6,880	4,293	2,841

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, 2013
(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	12,461	189	6,724	0	127	5,421
PROVED PLUS PROBABLE	61,882	2,642	21,627	14,025	300	23,289

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, 2013
(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	3,708	8.92
PROVED PLUS PROBABLE	Natural Gas	6,880	3.89

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, 2013

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.)
2014	97.50	4.25	3.88	2	0.95
2015	97.50	4.50	4.11	2	0.95
2016	97.50	4.75	4.35	2	0.95
2017	97.50	5.00	4.59	2	0.95
2018	97.50	5.25	4.82	2	0.95
2019	97.50	5.50	5.06	2	0.95
2020	98.54	5.63	5.18	2	0.95
2021	100.51	5.74	5.29	2	0.95
2022	102.52	5.86	5.40	2	0.95
2023	104.57	5.97	5.51	2	0.95

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, 2013. The reconciliation of changes in reserves is based on the previous year end occurring as at December 31, 2012.

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, 2012	2,487	8,615	11,102	415	1,435	1,850
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	633	(97)	535	105	(16)	89
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	(82)	61	(21)	(14)	11	(3)
Production	(456)	0	(456)	(76)	0	(76)
December 31, 2013	2,582	8,578	11,160	430	1,430	1,860

* 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	7,812	0	1,302

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
2014	0	0
2015	0	0
2016	0	0
2017	0	14,025
2018	0	0
TOTAL UNDISCOUNTED	0	14,025

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

a) Montney

Under its Farrell Creek joint venture with Canbriam Energy Inc. ("Canbriam"), 1 well (0.25 net) was drilled into the Montney Formation in 2013. Cumulatively, Canbriam has drilled 10 wells (3.25 net) for testing, production and land retention purposes. In 2014, operations will focus both on the eastern (100% WI lands) and western (JV lands) portion of Farrell Creek. On the eastern portion, a well was drilled in March 2014 at 1-1-83-25W6 for land retention purposes. On the western portion, a well is anticipated to be drilled at c-81-H/94-B-1 along with subsequent fracking and production being tied-in.

b) Gething

On June 18, 2010, Shell Canada Energy elected not to continue to the development stage and as a result shut-in the gas facility in early July 2010. As per the joint venture agreement, the Corporation is now the operator of the Gething project and will retain 56 net sections (35,860 net acres), the gas facility, the additional wells and the related infrastructure at no additional cost. The Corporation has minimized its expenditures on the Gething project and has deactivated both the gas plant and related sales pipeline subject to higher gas prices in the future.

In June of 2012, the Corporation acquired approximately 26,500 hectares of shallow rights land (including the Gething) directly offsetting the Corporations land in the Farrell Creek area. Subsequently, in July of 2013, the Corporation allowed these rights to revert back to the province of British Columbia due to the lack of positive development economics.

Item 6.2 Properties with No Attributed Reserves

The Corporation's unproved properties are comprised of 18,752 gross (10,094 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 Corporation has 2,385 hectares (2,210 net) of unproved properties in western Canada which primary term expires within one year. The Corporation intends to extend 2,120 hectares (1,945 net) of these properties by drilling two wells.

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, 2013, 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%
	127	33	300	28

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, 2013 the Corporation estimated the total future asset retirement obligations to be $1.8 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
	3,203	590	25	17.25

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 2013, the Corporation incurred $0.1 million of acquisition and retention costs for unproved properties and $1.1 million (net) of exploration and development costs in western Canada.

Item 6.7 Exploration and Development Activities
During 2013, Canbriam, as part of its joint venture with the Corporation, drilled and cased 1 gas well (0.25 net) into the Montney Formation.

For the year ended December 31, 2013, gross capital expenditures (net of British Columbia government incentive Summer Drilling and Deep Royalty Credits earned) totaled $1.3 million (2012: $2.3 million), compared to a budgeted capital expenditure of $1.4 million (2012: $2.0 million).

The Corporation's capital budget is approved on an annual basis and subsequently reviewed on a quarterly basis by the Board of Directors. The Corporation's Board of Directors has approved a total capital expenditure budget for 2014 of $18.2 million (net), including an estimated $0.3 million for capitalized overhead. CSRI has budgeted for $4.6 million (net) of capital expenditures for the first quarter 2014.

Cash administration expenses (general and administrative expenses excluding share-based compensation) for 2014 are expected to total $1.5 million (2013: $1.7 million), before capitalization of exploration and development related overhead. The Corporation has budgeted for operating netbacks from the Farrell Creek Montney operations of $2.3 million during 2014 (2013: $0.8 million).

Item 6.8 Production Estimates
The following table summarizes the Corporation's estimated future average daily production volumes for 2014.

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

	2014 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	984	952	2,582	2,493	430	416
Proved Developed Nonproducing	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0
Total Proved	984	952	2,582	2,493	430	416
Total Probable	20	19	8,578	8,106	1,430	1,351
Total Proved Plus Probable	1,003	971	11,160	10,599	1,860	1,767

Item 6.9 Production History
The following table summarizes the Corporation's average gross daily production volumes for the financial year ended December 31, 2013.

Table 6.9.1
PRODUCTION HISTORY YEAR ENDED DECEMBER 31, 2013

Natural Gas (MMcf/d)		Average Per Unit of Volume ($/Mcf) Production			
Yearly Quarter	Production Volume (1)	Price	Royalties (2)	Costs (3)	Netbacks
1st Quarter	1.40	3.00	0.27	1.43	1.57
2nd Quarter	1.29	3.43	0.45	1.68	1.75
3rd Quarter	1.20	2.64	0.48	1.43	1.21
4th Quarter	1.12	3.37	0.26	0.87	2.50

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.