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

This Statement of Reserves Data and other Oil and Gas Information for Canadian Spirit Resources Inc. ("CSRI" or the "Corporation") is dated April 23, 2019. The effective date of the information provided in this statement is December 31, 2018 unless otherwise indicated. The information was prepared between December 31, 2018 and April 23, 2019.

GLJ Petroleum Consultants Ltd. ("GLJ") was engaged to prepare an independent reserve assessment on the Corporation's lands as at December 31, 2018 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, 2018 and accordingly, some 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.

The following table summarizes the Corporation's oil and gas reserves as of December 31, 2018 based on forecast price and cost assumptions.

**SUMMARY OF RESERVES**
**as at December 31, 2018**
**FORECAST PRICES AND COSTS (4)**

| | Shale Gas (1) | | Barrels of Oil Equivalent | |
|---|---|---|---|---|
| | Gross(2) (MMcf) | Net(3) (MMcf) | Gross(2) (MMcf) | Net(3) (MMcf) |
| **PROVED** | | | | |
| **Producing** | - | - | - | - |
| **Developed Non-Producing** | 1,378 | 1,339 | 230 | 223 |
| **Undeveloped** | - | - | - | - |
| **TOTAL PROVED** | 1,378 | 1,339 | 230 | 223 |
| **TOTAL PROBABLE** | 8,690 | 8,321 | 1,448 | 1,387 |
| **TOTAL PROVED PLUS PROBABLE** | 10,068 | 9,660 | 1,678 | 1,610 |

(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 the Corporation's working interest share of the remaining reserves before deduction of royalties and without including any royalty interests.
(3) "Net Reserves" are the Corporation's working interest share of remaining reserves after deduction ofroyalty obligations, plus royalty interests.
(4) May not add due to rounding.

The following tables summarize the net present value and undiscounted value of the Corporation's reserves based on forecast price and cost assumptions as at December 31, 2018.

**SUMMARY OF NET PRESENT VALUES**
**As at December 31, 2018**
**(thousands of dollars) (1)**

| | Discounted at | | | | |
|---|---|---|---|---|---|
| | **0%** | **5%** | **10%** | **15%** | **20%** |
| **PROVED** | | | | | |
| **Producing** | - | - | - | - | - |
| **Developed Non-Producing** | (20) | 63 | 85 | 85 | 79 |
| **Undeveloped** | - | - | - | - | - |
| **TOTAL PROVED** | (20) | 63 | 85 | 85 | 79 |
| **TOTAL PROBABLE** | 8,737 | 2,665 | 422 | (482) | (844) |
| **TOTAL PROVED PLUS PROBABLE** | 8,717 | 2,728 | 507 | (396) | (765) |

(1) May not add due to rounding.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)**
**As at December 31, 2018**
**FORECAST PRICES AND COSTS**
**(thousands of dollars) (2)**

| RESERVE CATEGORY | Sales Revenue | Royalties | Operating Costs | Development Costs | Abandon-ment Costs and Reclamation | BT (1) (3) Future Net Revenue |
|---|---|---|---|---|---|---|
| Proved Producing | - | - | - | - | - | - |
| Proved Developed Non-Producing | 4,065 | 116 | 3,516 | 179 | 274 | (20) |
| Proved Undeveloped | - | - | - | - | - | - |
| **Total Proved** | **4,065** | **116** | **3,516** | **179** | **274** | **(20)** |
| **Total Probable** | **31,887** | **1,387** | **11,001** | **10,464** | **298** | **8,737** |
| **Total Proved Plus Probable** | **35,952** | **1,503** | **14,517** | **10,642** | **572** | **8,717** |

(1) BT = Before Taxes.
(2) May not add due to rounding.
(3) After Taxes = Before Taxes.

The following table discloses, by production type, 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.

**NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION TYPE**
**As at December 31, 2018**
**FORECAST PRICES AND COSTS**

| RESERVE CATEGORY | PRODUCTION TYPE | Future Net Revenue BT Discounted (10%/Yr.) ($ Thousands) (1) | Unit Value BT Discounted (10%/yr) $/boe (1)(2) |
|---|---|---|---|
| **PROVED** | Shale Gas | 85 | 0.38 |
| **PROVED PLUS PROBABLE** | Shale Gas | 507 | 0.31 |

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

## PRICING ASSUMPTIONS

### Forecast Prices and Assumptions

GLJ used the following pricing, exchange rate and inflation assumptions in estimating the Corporation's reserves data:

## FORECAST
## 3 CONSULTANTS' AVERAGE (1)
## As at December 31, 2018

| 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.) |
|---|---|---|---|---|---|
| **2019** | 58.58 | 3.00 | 1.42 | 0.0 | 0.7567 |
| **2020** | 64.60 | 3.13 | 1.94 | 2.0 | 0.7817 |
| **2021** | 68.20 | 3.33 | 2.41 | 2.0 | 0.7967 |
| **2022** | 71.00 | 3.51 | 2.76 | 2.0 | 0.8033 |
| **2023** | 72.81 | 3.62 | 2.93 | 2.0 | 0.8067 |
| **2024** | 74.59 | 3.70 | 3.06 | 2.0 | 0.8083 |
| **2025** | 76.42 | 3.77 | 3.12 | 2.0 | 0.8083 |
| **2026** | 78.40 | 3.85 | 3.19 | 2.0 | 0.8083 |
| **2027** | 79.98 | 3.92 | 3.26 | 2.0 | 0.8083 |
| **2028** | 81.59 | 4.01 | 3.35 | 2.0 | 0.8083 |
| **2029** | 83.22 | 4.08 | 3.42 | 2.0 | 0.8083 |

Escalation rate of 2.0% thereafter

(1) The average of the escalated price forecasts of three independent reserve evaluators, namely GLJ, McDaniels & Associates Consultants Ltd. and Sproule Associates Limited.

The Corporation's average realized price received for natural gas for the year ended December 31, 2018 (calculated over 120 producing days as wells were shut-in May 1, 2018) was $1.77 CDN/mcf.

## RECONCILIATION OF CHANGES IN RESERVES

The following table sets forth a reconciliation of the total gross proved, probable and proved plus probable reserves as at December 31, 2018 based on forecast price and cost assumptions.

## RECONCILIATION OF CHANGES IN COMPANY GROSS RESERVES
## As at December 31, 2018

| FACTORS | Shale Gas | | | BOE | | |
|---|---|---|---|---|---|---|
| | Proved (MMcf) | Probable (MMcf) | Proved + Probable (MMcf) | Proved (Mboe) | Probable (Mboe) | Proved + Probable (Mboe) |
| December 31, 2017 | 1,550 | 8,756 | 10,306 | 258 | 1,459 | 1,718 |
| Discoveries | - | - | - | - | - | - |
| Extensions, infill drilling & Improved Recovery | - | - | - | - | - | - |
| Technical Revisions | (1) | - | (1) | - | - | - |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | (105) | (66) | (171) | (18) | (11) | (29) |
| Production | (65) | - | (65) | (11) | - | (11) |
| December 31, 2018 | 1,378 | 8,690 | 10,068 | 230 | 1,448 | 1,678 |

Changes to reserves between the current and the previous reporting periods are due to a number of factors. Technical revisions occurred due to the increase in natural gas shrinkage at the Company's production facility along with increased decline rates as a result of the eight-month shut-in of producing wells in 2018. These two technical factors combine to cause the property to reach its economic limit sooner resulting in a loss of reserves. Economic adjustments are the result of changes in long term price forecasts, inflation rates and regulatory changes. Production adjustments are the result of the natural depletion of reserves.

## ADDITIONAL INFORMATION RELATING TO RESERVES DATA

***Undeveloped Reserves***

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves associated with the Corporation's assets are planned to be developed over the next two to five years.

In some cases, it will take longer than two to three years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion, or to changes in geological interpretation, including reservoir continuity and quality); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

***Proved Undeveloped Reserves***

The Corporation has no proved undeveloped reserves as at December 31, 2018.

***Probable Undeveloped Reserves***

The following table sets forth the probable undeveloped reserves, by product type, first attributed as reserves for the following financial periods and first attributed to CSRI assets for the year ended December 31, 2018.

| | Shale Gas (MMcf) | | Oil Equivalent | |
|---|---|---|---|---|
| | First Attributed [1] | Total at Year-end | First Attributed | Total at Year-end |
| 2016 | - | 7,921 | - | 1,320 |
| 2017 | - | 8,316 | - | 1,386 |
| 2018 | - | 8,316 | - | 1,386 |

[1] "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

***Significant Factors or Uncertainties***

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 gas prices and reservoir performance. Such revisions can be either positive or negative. The reserve estimates of the Corporation's 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.

### *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.

**FUTURE DEVELOPMENT COSTS**
**FORECAST PRICES AND COSTS**
**(Thousands of dollars) (1) (2)**

| Year | Proved Reserves | Proved Plus Probable Reserves |
|---|---|---|
| **2019** | - | - |
| **2020** | - | - |
| **2021** | - | - |
| **2022** | - | - |
| **2023** | - | 10,456 |
| **THEREAFTER** | 179 | 186 |
| | | |
| **TOTAL UNDISCOUNTED** | 179 | 10,642 |

(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 Board of Directors 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.

### *Other Oil and Gas Information*

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's primary core area is the Triassic Montney Formation shale gas ("Montney"). The Corporation also has oil and gas properties associated with the Cretaceous Gething Formation coals and tight sands.

The Montney shale gas project has 13 wells drilled with 10 (net 3.25) drilled on joint venture ("JV") lands and three on 100% CSRI lands. The Corporation has 5 JV wells that produce through the joint venture gas plant (CSRI 35%) and are pipeline connected to the Spectra Energy mainline. These 5 wells were shut-in May 1, 2018 due to uneconomic natural gas pricing. The JV plant has a processing capacity of 10 MMcf/day of natural gas. Of the remaining eight wells that were drilled, six are cased and suspended, one has been abandoned, and one is standing cased waiting on abandonment.

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.

### *Properties with No Attributed Reserves*

The Corporation's unproved properties are comprised of 14,435 gross (8,935 net) hectares of Montney rights and 11,433 gross (11,303 net) hectares of Gething 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.

### *Forward Contracts*

As at December 31, 2018, the Corporation had not entered into any forward contracts, transportation agreements or other future obligations.

### *Tax Horizon*

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

### *Costs Incurred*

The Corporation incurred $0.2 million of costs related to retention of unproved properties and $0.2 million of costs related to miscellaneous intangible and tangible costs. (These costs exclude non-cash charges and capitalized overhead).

### *Exploration and Development Activities*

In 2018, the Corporation drilled no development or exploration wells. Future drilling activity will be limited until natural gas prices support the economics of these capital projects.

### *Production Estimates*

The GLJ Reserve Report forecasts nil production in 2019.

### *Production History*

The following table summarizes the Corporation's average gross daily production volumes for the financial year ended December 31, 2018.

| Shale Gas (MMcf/d) | | Average Per Unit of Volume ($/Mcf) Production | | | |
|---|---|---|---|---|---|
| Yearly Quarter | Production Volume (1) | Price | Royalties | Costs (2) | Netbacks |
| 1st Quarter | 0.54 | 1.88 | 0.00 | 1.79 | 0.09 |
| 2nd Quarter | 0.55(3) | 1.43 | 0.00 | 3.60 | (2.17) |
| 3rd Quarter | N/A | N/A | N/A | N/A | N/A |
| 4th Quarter | N/A | N/A | N/A | N/A | N/A |

(1) Production volumes reflect the Corporation's share of average daily production volume, before deduction of royalties.
(2) Production costs include transportation costs and production operating costs.
(3) Production was shut in May1, 2018. The second quarter 2018 per unit production results were calculated over 31 producing days.