SOFTROCK MINERALS LTD.
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION
(Form 51-101F1)

Part 1 – Date of Statement

This statement of reserves data and other oil and gas information is dated March 24, 2015

The effective date is December 31, 2014.

The preparation date is March 3, 2015.

Part 2 – Disclosure of Reserves Data

The following is a summary of the oil and natural gas reserves and the value of future net revenue of SOFTROCK MINERALS LTD.(the "Company") as evaluated by Chapman Petroleum Engineering Ltd. ("Chapman") as at December 31, 2014_, and dated March 6, 2015 (the "Chapman Report"). Chapman is an independent qualified reserves evaluator and auditor.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Chapman Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Chapman Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

All monetary values presented in this document are expressed in terms of Canadian (US) dollars.

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014__

	Company Reserves[1]							
	Light and Medium Oil		Heavy Oil		Natural Gas[9]		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing[2][6]		2						
Developed Non-Producing[2][7]								
Undeveloped[2][8]								
TOTAL PROVED[2]		2						
TOTAL PROBABLE[3]		2						
TOTAL PROVED + PROBABLE[2][3]		5						
TOTAL POSSIBLE[4]								
TOTAL PROVED + PROBABLE + POSSIBLE								

SUMMARY OF NET PRESENT VALUES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	Net Present Values of Future Net Revenue									
	Before Income Tax Discounted at					After Income Tax Discounted at				
Reserves Category	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M
PROVED										
Developed Producing[2][6]	236	167	128	103	87	236	167	128	103	87
Developed Non-Producing[2][7]										
Undeveloped[2][8]										
TOTAL PROVED[2]	236	167	128	103	87	236	167	128	103	87
TOTAL PROBABLE[3]	254	115	64	42	29	254	115	64	42	29
TOTAL PROVED + PROBABLE[2][3]	**490**	**282**	**192**	**145**	**116**	**490**	**282**	**192**	**145**	**116**
TOTAL POSSIBLE[4]										
TOTAL PROVED + PROBABLE + POSSIBLE										

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

	Revenue ($M)	Royalties ($M)	Operating Costs ($M)	Development Costs ($M)	Abandonment and Reclamation Costs ($M)	Future Net Revenue Before Income Taxes ($M)	Income Taxes ($M)	Future Net Revenue After Income Taxes ($M)
Total Proved[2]	236	0	0	0	0	236	0	236
Total Proved Plus Probable[2][3]	490	0	0	0	0	490	0	490
Total Proved Plus Probable Plus Possible[4]								

FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2014

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($M)
Total Proved[2]	Light and Medium Oil (including solution gas and other by-products)	128
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable[2][3]	Light and Medium Oil (including solution gas and other by-products)	192
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable Plus Possible[4]	Light and Medium Oil (including solution gas and other by-products)	
	Heavy Oil (including solution gas and other by-products)	
	Natural Gas (including by-products but not solution gas)	

OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMEBR 31, 2014

	Reserves						Net Present	Unit Values
	Oil		Gas(9)		NGL		Value (BIT)	@ 10%/yr
Reserve Group by Category	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl	10% M$	
Light and Medium Oil								
Proved								
Developed Producing		2	0	0	0	0	128	51.92
Developed Non-Producing								
Undeveloped								
Total Proved		**2**	**0**	**0**	**0**	**0**	**128**	**51.92**
Probable		2	0	0	0	0	64	28.48
Proved Plus Probable		**5**	**0**	**0**	**0**	**0**	**192**	**40.70**
Possible								
Proved + Probable + Possible								
Heavy Oil								
Proved								
Developed Producing								
Developed Non-Producing								
Undeveloped								
Total Proved								
Probable								
Proved Plus Probable								
Possible								
Proved + Probable + Possible								
Assoc & Non-Assoc Gas								
Proved								
Developed Producing								
Developed Non-Producing								
Undeveloped								
Total Proved								
Probable								
Proved Plus Probable								
Possible								
Proved + Probable + Possible								

Notes:

1. "Gross Reserves" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.
2. "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
3. "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
4. "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
5. "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.
6. "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
7. "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
8. "Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.
9. Includes associated, non-associated and solution gas where applicable.

Part 3 - Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Company operated, as at December 31, 2014, reflected in the reserves data disclosed above under "Part 2 – Disclosure of Reserves Data". The forecast price assumptions assume the continuance of current laws and regulations and take into account inflation with respect to future operating and capital costs. There will be adjustments to field prices from the benchmarks below

CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES

January 1, 2015

Date	WTI [1] $US/STB	Brent Spot (ICE)[2] $US/STB	AB Synthetic Crude Price [3] $CDN/STB	Western Canada Select [4] $CDN/STB	Exchange Rate $US/$CDN
			HISTORICAL PRICES		
2004	41.51	38.26	52.89	37.52	0.77
2005	56.64	54.57	69.16	43.25	0.83
2006	66.05	65.16	72.88	50.40	0.88
2007	72.34	72.44	75.57	53.17	0.94
2008	99.67	96.94	102.98	83.88	0.94
2009	61.95	61.74	76.77	53.04	0.88
2010	79.48	79.61	80.56	66.58	0.97
2011	94.88	111.26	102.45	77.43	1.01
2012	94.05	111.63	92.56	71.70	1.00
2013	97.98	108.56	100.17	75.76	0.97
2014	93.12	99.43	101.07	82.07	0.91
CONSTANT PRICES (The average of the first-day-of-the-month price for the preceding 12 months-SEC)					
	94.35	101.25	102.83	83.33	0.91
FORECAST PRICES					
2015	65.00	69.55	72.86	59.02	0.88
2016	75.00	80.25	84.23	68.22	0.88
2017	81.00	86.67	91.05	73.75	0.88
2018	85.00	90.95	95.59	77.43	0.88
2019	90.00	96.30	101.27	82.03	0.88
2020	94.00	100.58	105.82	85.71	0.88
2021	96.00	102.72	108.09	87.55	0.88
2022	96.00	102.72	108.09	87.55	0.88
2023	97.92	104.77	110.27	89.32	0.88
2024	99.88	106.87	112.50	91.12	0.88
2025	101.88	109.01	114.77	92.96	0.88
2026	103.91	111.19	117.08	94.84	0.88
2027	105.99	113.41	119.45	96.75	0.88
2028	108.11	115.68	121.85	98.70	0.88
2029	110.27	117.99	124.31	100.69	0.88
2030	112.48	120.35	126.82	102.72	0.88

Constant thereafter

Notes: [1] West Texas Intermediate quality (D2/S2) crude (40API) landed in Cushing, Oklahoma.
[2] The Brent Spot price is estimated based on historic data.
[3] Equivalent price for Light Sweet Crude (D2/S2) & Synthetic Crude (34API) landed in Edmonton.
[4] Western Canada Select (20.5API), spot price for B.C., Alberta, Saskatchewan, and Manitoba.

The Company's weighted average prices received this fiscal year are: $__0___/Mscf for natural gas and $_83.14____/STB.

Part 4 – Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at December 31, 2014 against such reserves as at December 31, 2013 based on the forecast price and cost assumptions:

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2014

	Light and Medium Oil					Heavy Oil					Associated and Non-Associated Gas				
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (MMscf)	Gross Probable (MMscf)	Gross Proved Plus Probable (MMscf)	Gross Possible (MMscf)	Gross Proved Plus Probable Plus Possible (MMscf)
At Dec. 31, 2013	**3**	**1**	**4**												
Production(Sales)	1	0	0												
Acquisitions	0	0	0												
Dispositions	0	0	0												
Discoveries	0	0	0												
Extensions & Improved Recovery	0	1	1												
Economic Factors															
Technical Revisions															
At Dec. 31, 2014	**2**	**2**	**5**												

Part 5 – Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMscf)**	**Natural Gas Liquids (Mbbl)**
Aggregate prior to 201_	0			
20	0			
20	0			
20	0			

The Company had no proved undeveloped reserve as at December 31, 2014 or in prior years.

The following table sets forth the volumes of probable undeveloped net reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2012	0			
2012	0			
2013	0			
2014	0			

The following table sets forth the volumes of possible undeveloped reserves that were first attributed for each of the Company's product types for the most recent three financial years and in the aggregate before such time:

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Aggregate prior to 2012	0			
2012	0			
2013	0			
2014	0			

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developig those undeveloped reserves.

Probable Undeveloped Reserves

The Company's probable undeveloped reserves are 0.

Possible Undeveloped Reserves

The Company's Possible Undeveloped reserves are the same only larger volumes as the Probable Undeveloped reserves and the same comments apply.

Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. All of the Company's reserves are evaluated by Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rates; industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks the Company faces in this market. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward looking statements and accordingly, no assurance can be given that any events anticipated by the forward looking statements will transpire or occur, if any of them do, what benefits the Company can derive from. The reader is cautioned not to place undue reliance on this forward looking information.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which have been deducted in the estimation of the future net revenues of the proved and probable reserves.

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)
2015	0	0
2016	0	0
2017	0	0
2018	0	0
2019	0	0
Total for five years	0	0
Remainder	0	0
Total for all years	0	0

The Company has been successful in raising its required capital through equity financings and plans to continue to do so for the development costs specified above. The effect of the costs of the expected funding would have no impact on the revenues or reserves currently being reported.

Part 6 – Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a royalty interest as at _December 31, 2014:

	Oil		Natural Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Grand Forks Area				
Producing	2	.06		
Non-producing				

[1] Total number of wells in which the Company has a working interest.
[2] Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

All of the Company's producing wells are in Grand Forks area, Alberta

EXAMPLE:

{...located onshore in the Provost field, Alberta (one producing and one currently shut-in) and in the Noel field B.C. (one producing). The only shut-in production as at March 31, 2008 is a gas/oil well in Provost, which is tied in and was producing at marginal rates, but is currently experiencing some mechanical problems in the well bore, which are being investigated.

The Noel well a-87-B has additional uncompleted zones for which reserves have been assigned and which require a recompletion in order to produce. The Company plans to exploit these zones once certain surrounding land negotiations have been completed, likely later in 2008.

All the Company's wells are currently tied-in to facilities and pipelines.}

Properties with No Attributed Reserves

The Company

Holds a 20% working interest in two suspended wells in the Minihik area of central west Alberta and a 15% working interest in one suspended well in the Manito area of Western Saskatchewan. Also in Alberta the company holds a 2l/2 % GORR with no deductions in a well awaiting completion in the Charlie Lake oil field of Northwest Alberta and a 47% working interest in a suspended Cardium well in the Ferrier field of Central Alberta

EXAMPLE:

{, through a farm-in arrangement has the right to earn up to 50% working interest in two oil shale exploration permits in the Pasquia Hills area of Saskatchewan, comprising a total of 155,433 gross acres of land.

Under the terms of the agreement, the Company is to fund 100 percent of the exploration and related costs on the project, up to $5,000,000, scheduled over a five year period, earning increased interests on a gradual basis. The 2007 funding commitment of $500,000 was met, resulting in a current interest of 11.1 percent on the project (i.e. 17,253 net acres). The 2008 funding commitment is for $1,000,000, upon which the Company's earned interest will be 33 1/3 percent (i.e. 51759 net acres). The Company expects to meet the 2008 commitment, by July 31, 2008. Thereafter, additional interests will be earned directly proportional to additional funding, up to the maximum stated above.

The oil shale permits were issued on March 7, 2007 for a five year term, after which the prospective lands would be converted to a lease and the remainder of the land would be relinquished to the Crown.}

Forward Contracts

Currently, the Company has no forward contracts.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated abandonment and restoration costs used by Chapman are based on the AER Directive 11, which details the typical costs of abandonment and reclamation by well type in each specific geographic region. The Company expects to have costs relating to _0____ net wells, including the location to be drilled. All costs have been included in the Chapman report.

FUTURE ABANDONMENT AND RESTORATION COSTS

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Estimated Using Forecast Prices and Costs (10% Discounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (10% Discounted) ($M)
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
Total for three years	0	0	0	0
Remainder	0	0	0	0
Total for all years	0	0	0	0

Tax Horizon

The Company is not expected to become taxable under the proved plus probable plus possible cash flows forecast in this report.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ended December 31, 2014

Property Acquisition Costs ($M)		Exploration Costs ($M)	Development Costs ($M)
Proved Properties	Unproved Properties		
0	0	0	0

The Company also had exploration costs of $_______0_______ expended on the __________ project, which is not a conventional oil and gas property.

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2014 financial year:

	Exploratory Wells		Development Wells	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Dry Holes	0	0	0	0
Total Completed Wells	0	0	0	0

[1] Total number of wells in which the Company has a working interest.
[2] Total number of wells in which the Company has a working interest multiplied by the Company working interest in each well.

The Company did not drill or develop any additional reserves in the fiscal year.

Production Estimates

The following table sets forth the volume of production estimated by Chapman for 2015 (12_ mo.):

TOTAL PROVED RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Grand Forks	0.307			
Total for all areas	**0.307**			

TOTAL PROVED PLUS PROBABLE RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
	0.318			-
Total for all areas	**0.318**			

These values are gross to Company's working interest before the deduction of royalties payable to others.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year:

	Three Months Ended March 31, 2014	Three Months Ended June 30, 2014	Three Months Ended September 30 , 2014	Three Months Ended December _ 31, 2014
Average Daily Production				
Light and Medium Oil (Bbl/d)	0.9	0.8	0.9	0.8
Natural Gas (Mscf/d)				
Average Net Prices Received				
Light and Medium Oil ($/Bbl)	$76.76	$86.39	$94.92	$77.02
Natural Gas ($/Mscf)				
Royalties				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)				
Production Costs				
Light and Medium Oil ($/Bbl)	0	0	0	0
Natural Gas ($/Mscf)				
Netback Received				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)				

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
MSTB	1,000 stock tank barrels
Bbls/d	barrels per day
NGLs	natural gas liquids
STB	stock tank barrels of oil
STB/d	stock tank barrels of oil per day

Natural Gas

Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
Mscf/d	thousand standard cubic feet per day
MMscf/d	million standard cubic feet per day
MMBTU	million British Thermal Units
Bscf	billion standard cubic feet
GJ	gigajoule

Other

AECO	Niska Gas Storage's natural gas storage facility located at Suffield, Alberta.
BIT	Before Income Tax
AIT	After Income Tax
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mscf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
$M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade