PINECREST ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

(COMPLYING WITH FORM 51-101F1)

Year Ended December 31, 2014

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

ABBREVIATIONS & DEFINITIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbls	Thousand barrels
Bbls/d	barrels per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
GJ	gigajoule
MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of one Bbl for six Mcf of natural gas
BOE/d	barrel of oil equivalent per day
km	kilometre
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
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

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500

NOTES ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Caution Respecting Reserves Information

The determination of crude oil, NGLs and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of our anticipated crude oil, NGL and natural gas reserves does not represent the fair market value of our proposed reserves.

Definitions

Certain terms used in this annual information form (the "**Annual Information Form**" or "**AIF**") in describing reserves and other crude oil, NGL and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 (as defined herein or the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10; it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**API**" means the American Petroleum Institute;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**CSA 51-324**" means Staff Notice 51-324 – Glossary to NI 51-101;

"**Current Production**" means the average daily gross production from the Company's oil and gas assets for the twelve month period ended December 31, 2013;

"**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;

"**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 certainly;

"**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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing;

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems;

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive;

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells;

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Raging River is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**gross**" means: (a) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest;

"**net**" means: (a) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (b) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (c) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**P+P Reserves**" means Proved Reserves plus Probable Reserves;

"**PDP Reserves**" means proved developed producing reserves;

"**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;

"**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;

"**Reserve Life Index**" or "**RLI**" is calculated by dividing year-end reserves by expected Current Production;

"**Reserves Data**" has the meaning set forth under the heading "*Statement of Reserves Data and other Oil and Gas Information* " in this Annual Information Form;

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion;

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status; and

"**working interest**" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook (as defined herein).

Forward-looking statements and other information contained herein concerning the oil and gas industry and our general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Pinecrest believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Pinecrest is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "**$**" or "**dollars**" are to Canadian dollars. All financial information has been presented in Canadian dollars in accordance with applicable GAAP in Canada.

BARREL OF OIL EQUIVALENCY

The term "BOE" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalence 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 compares 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.

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

The statement of reserves data and other oil and gas information (the "**Reserves Data**") of Pinecrest Energy Inc. (“the Company” or “Pinecrest”) is dated January 7, 2015 and the effective date of the statement is December 31, 2014, unless otherwise indicated.

Part 2 Disclosure of Reserves Data and Other Information

Sproule Associates Limited (“Sproule”) has prepared a report dated January 7, 2015, (the “Sproule Report”), in which it has evaluated as at December 31, 2014 the oil and natural gas reserves attributable to 100 percent of the properties of the Company. . The Reserves Data summarizes the crude oil, NGLs and natural gas reserves associated with the Company's assets and the net present values of future net revenue for such reserves using forecast prices and costs. The crude oil, NGLs and natural gas reserve estimates presented in the Sproule Report are based on the guidelines contained in the COGE Handbook and the reserve definitions contained in both NI 51-101 and the COGE Handbook. A summary of those definitions are set forth in the glossary to this Annual Information Form. Sproule was engaged to provide evaluations of Proved Reserves and P+P Reserves and no attempt was made to evaluate possible reserves. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Company believes is important to the readers of this information.

All of the Company's reserves are in Canada and, specifically, in Alberta.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable crude oil, NGLs and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Company's assets may vary from the information presented herein and such variations could be material.

The Sproule Report also presents the estimated net value of future revenue of Pinecrest’s properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs, 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 Pinecrest and/or the operator of its properties, 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 Sproule in preparing the Sproule Report and were accepted as represented without independent verification. In the absence of such information, Sproule relied, with the approval of Pinecrest, upon its opinion of reasonable practice in the industry. All information provided to Sproule was as at December 31, 2014 and, accordingly, certain of such information may not be representative of current conditions.

Certain natural gas volumes have been converted to boe on the basis of six mcf to one bbl. Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 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.

Certain crude oil volumes have been converted to mcfe on the basis of one bbl to six mcf. Disclosure provided herein in respect of mcfe may be misleading, particularly if used in isolation. A mcfe conversion ratio of 1 bbl: 6 mcf 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 Sproule 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, in the aggregate, the Company's gross and net proved reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" means future prices and costs used by Sproule in the Sproule Report that are generally accepted as being a reasonable outlook of the future, or fixed or currently determinable future prices or costs to which the Company is bound.

Table 1 NI 51-101

Summary of Oil and Natural Gas Reserves
as of December 31, 2014
Forecast Prices and Costs

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		SOLUTION GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	3573.1	3006.4	-	-	-	-	-	-
Developed Non-Producing			-	-	-	-	-	-
Undeveloped	169.9	144.1	-	-	-	-	-	-
TOTAL PROVED	**3743.0**	**3150.5**	-	-	-	-	-	-
PROBABLE	2850.9	2344.0	-	-	-	-	-	-
TOTAL P + P	**6593.9**	**5494.5**	-	-	-	-	-	-

The following table discloses, in the aggregate, the net present value of the Company's Future Net Revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting Future Income Tax expenses, and calculated without discount and using discount rates of 0 percent, 5 percent, 10 percent, 15 percent and 20 percent
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Table 2 NI 51-101

Summary of Net Present Values of Future Net Revenue
as of December 31, 2014
Forecast Prices and Costs

	Net Present Values of Future Net Revenue[1] Before Income Taxes Discounted at (%/year)					Bef Tax Net Val
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**10%/yr ($/BOE)**
PROVED:						
Developed Producing	110,229	90,472	76,290	65,792	57,799	25.38
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	2,811	1,284	309	(335)	(772)	2.15
TOTAL PROVED	**113,040**	**91,756**	**76,600**	**65,457**	**57,027**	**24.31**
PROBABLE	106,780	64,451	41,362	27,725	19,139	17.65
TOTAL P+P	**219,820**	**156,208**	**117,962**	**93,182**	**76,166**	**21.47**

	NET PRESENT VALUES OF FUTURE NET REVENUE[1] AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
PROVED:					
Developed Producing	0.0	0.0	0.0	0.0	0.0
Developed Non-Producing	0.0	0.0	0.0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0.0
TOTAL PROVED	0.0	0.0	0.0	0.0	0.0
PROBABLE	0.0	0.0	0.0	0.0	0.0
TOTAL P+P	0.0	0.0	0.0	0.0	0.0

Notes:

(1) Net present value of future net revenues includes all resource income: sales of oil, gas, by-products, processing third party reserves and other income.

This table discloses, in the aggregate, certain elements of the Company's Future Net Revenue attributable to its proved reserves and it's proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount

Table 3 NI 51-101
Total Future Net Revenue
Undiscounted
as of December 31, 2014
Forecast Prices and Costs (1)(2)

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT /OTHER COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	356,558	55,143	173,563	6,944	7,868	113,040		
Total P+P	661,876	108,624	279,101	44,993	9,337	219,820		

Notes:

(1) Total revenue includes company revenue before royalty and includes other income (net of transportation costs).
(2) Royalties include Saskatchewan Capital Surtax, if applicable.

This table discloses, by production group, the net present value of the Company's Future Net Revenue attributable to its proved and its proved plus probable reserves, before deducting Future Income Tax expenses, estimated using forecast prices and costs, and calculated using a 10 percent discount rate. '

Table 4 NI 51-101
Net Present Value of Future Net Revenue
By Production Group
as of December 31, 2014
Forecast Prices and Costs

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/YR (1)	
			($/BOE)	($/Mcf)
Proved Reserves	Light and Medium Crude Oil	76,600	24.31	-
	Heavy Oil	-		
	Associated and Non-Associated Gas	-		
	Non-Conventional Oil and Gas Activities	-		
	Other income	-		
	Total	76.600		
P+P Reserves	Light and Medium Crude Oil	117,962	21.47	-
	Heavy Oil	-		
	Associated and Non-Associated Gas	-		
	Non-Conventional Oil and Gas Activities	-		
	Other income	-		
	Total	117,962		-

Notes:

(1) Unit values are based on net reserve volumes

Part 3 Pricing Assumptions Forecast Costs and Price Assumptions

Item 3.2 Forecast Prices Used in Estimates

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, NGL and natural gas benchmark reference pricing**,** inflation and exchange rates utilized by Sproule in the Sproule Report were Sproule's forecasts, as at December 31, 2014, as follows:

Table 5 NI 51-101
Summary of Pricing and Inflation Rate Assumptions
As of December 31, 2014
Forecast Prices and Costs [(1)(2)(3)]

	OIL		NATURAL GAS	NATURAL GAS LIQUIDS			
Year	**Canadian Light Sweet Crude 40° API ($Cdn/bbl)**	**Western Canada Select 20.5° API ($Cdn/ Bbl))**	**AECO Gas Price ($Cdn/ MMbtu)**	**Pentanes Plus ($Cdn/Bbl)**	**Butanes ($Cdn/Bbl)**	**INFLATION RATE %/Year [(4)]**	**EXCHANGE RATE ($US/$Cdn [(5)]**
Historical							
2010	-	67.21	4.16	84.21	57.99	1.2	0.971
2011	-	77.09	3.72	104.12	70.93	1.6	1.012
2012	-	73.08	2.43	100.76	64.48	1.3	1.001
2013	-	73.78	3.13	105.48	69.88	0.8	0.971
2014	94.18	82.04	4.50	102.33	68.02	1.4	0.905
Forecast							
2015	70.35	60.50	3.32	78.60	50.34	1.5	0.850
2016	87.36	75.13	3.71	97.60	62.51	1.5	0.870
2017	98.28	84.52	3.90	109.80	70.32	1.5	0.870
2018	99.75	85.79	4.47	111.44	71.37	1.5	0.870
2019	101.25	87.07	5.05	113.12	72.44	1.5	0.870
2020	103.85	89.31	5.13	116.02	74.31	1.5	0.870
2021	105.40	90.65	5.22	117.76	75.42	1.5	0.870
2022	106.99	92.01	5.31	119.53	76.55	1.5	0.870
2023	108.59	93.39	5.40	121.32	77.70	1.5	0.870
2024	110.22	94.79	5.49	123.14	78.87	1.5	0.870
2025	111.87	96.21	5.58	124.99	80.05	1.5	0.870

Notes:

(1) This summary table identifies benchmark pricing schedules that might apply to a reporting issuer.
(2) As at December 31, 2014.
(3) Product sale prices will reflect these reference prices with further adjustment for quality and transportation to point of sale.
(4) Inflation rate for forecasting prices and costs.
(5) The exchange rate used to generate the benchmark reference pricing schedules that might apply to a reporting issuer.

Part 4 Reconciliation of Changes in Reserves and Future Gross Revenue

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation of Pinecrest's gross reserves based on forecast prices and costs.

Table 6 NI 51-101
Reconciliation of Gross Reserves[1]
By Principal Product Type
As of December31, 2014
Forecast Prices and Costs

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross P+P (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross P+P (Mbbls)
December 31, 2013[2]	**6,817.9**	**4,736.2**	**11,554.1**	**0.0**	**0.0**	**0.0**
Extensions	0	0	0	0.0	0.0	0.0
Infill Drilling	0	0	0	0.0	0.0	0.0
Improved Recovery	26.80	(5.4)	21.4	0.0	0.0	0.0
Technical Revisions	(2,412.0)	(1,878.4)	(4,290.4)	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	(7.6)	(2.3)	(9.9)	0.0	0.0	0.0
Economic Factors	(4.1)	0.8	(3.3)	0.0	0.0	0.0
Production	(678.0)	0.0	(678.0)	0.0	0.0	0.0
December 31, 2014[3]	**3,743.0**	**2,850.9**	**6,593.9**	**0.0**	**0.0**	**0.0**

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross P+P (MMcf)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross P+P (Mbbls)
December 31, 2013[2]	**0**	**0**	**0**	**0**	**0**	**0**
Extensions	0	0	0	0.0	0.0	0.0
Infill Drilling	0	0	0	0.0	0.0	0.0
Improved Recovery	0	0	0	0.0	0.0	0.0
Technical Revisions	0	0	0)	0.0	0.0	0.0
Discoveries	0	0	0	0.0	0.0	0.0
Acquisitions	0	0	0	0.0	0.0	0.0
Dispositions	0	0	0	0.0	0.0	0.0
Economic Factors	0	0	0	0.0	0.0	0.0
Production	0	0	0	0.0	0.0	0.0
December 31, 2014[3]	**0**	**0**	**0**	**0.0**	**0.0**	**0.0**

Notes:

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) As evaluated by Sproule in a report dated March 19, 2014 evaluating our crude oil, natural gas and natural gas reserves as at December 31, 2014.

(3) As evaluated in the Sproule Report.

Part 5. Additional Information Relating to Reserves Data

Item 5.1 Undeveloped Reserves

Undeveloped reserves are attributed by Sproule 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.

In general, once Proved and/or Probable undeveloped reserves are identified they are scheduled into our development plans. Pinecrest plans to develop our Proved and Probable undeveloped reserves within two years. In some cases, it will take longer than two years to develop these reserves. As such, the Company expects that the large majority of booked undeveloped projects will be completed within a two year time frame. 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); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion 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 following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Table 7 NI 51-101

Undeveloped Reserves Vintage by Principal Product Type

As of December 31, 2014

Forecast Prices and Costs

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Booked Gross	First Attributed	Booked Gross	First Attributed	Booked Gross	First Attributed	Booked Gross
Dec.31, 2010	98.8	196.3	0.0	0.0	9	42	1.3	6.5
Dec.31, 2011	1132.9	1187.9	0.0	0.0	79	414	25.2	62.2
Dec.31, 2012	2593.0	2879.7	0.0	0.0	42	62	3.8	6.8
Dec.31, 2013	109.9	1124.9	0.0	0.0	0	0	0.0	0.0
Dec.31, 2014	0.0	169.9	0.0	0.0	0	0	0.0	0.0

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Table 7 NI 51-101

Undeveloped Reserves Vintage by Principal Product Type

As of December 31, 20114

Forecast Prices and Costs

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross	First Attributed Gross	Booked Gross
Dec.31, 2010	206.1	299.7	0.0	0.0	9	16	1.4	2.5
Dec.31, 2011	1428.4	1450.1	0.0	0.0	86	233	27.2	35.0
Dec.31, 2012	3076.8	3171.2	0.0	0.0	46	56	4.2	5.6
Dec.31, 2013	594.8	2608.5	0.0	0.0	0	0	0.0	0.0
Dec.31, 2014	0.0	1422.9	0.0	0.0	0	0	0.0	0.0

Item 5.2 Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires 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 prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Pinecrest does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Item 5.3 Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below:

	FORECAST PRICES AND COSTS	
Year	Proved Reserves (M$)	P+P Reserves (M$)
2015	1,611	5,334
2016	4,557	19,710
2017	776	19,949
Remaining	-	-
Total (Undiscounted)	6,944	44,993

The future development costs are capital expenditures required in the future for us to convert Proved non-producing and undeveloped reserves and Probable reserves to Proved developed producing reserves. The undiscounted development costs are $6.9 million for Proved reserves and $44.9 million for P+P Reserves (in each case based on forecast prices and costs).

On an ongoing basis, Pinecrest will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic.

Part 6. Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2014:

	Oil Wells				Natural Gas Wells			
	Producing(1)		Non-Producing(2)		Producing(1)		Non-Producing(2)	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Alberta	179	95.2	71	41.2	-	-	2	0.5
Saskatchewan	-		3	1.5	-	-	-	-
Total	179	95.2	74	42.6	-	-	2	0.5

Notes:

(1) Includes wells that are temporarily shut in but are capable of production.
(2) Includes wells that are not capable of production but are not yet abandoned. All non-producing oil and natural gas wells are located near existing infrastructure.
(3) Gross means the number of wells in which we have a working interest.
(4) Net means the number of wells obtained by aggregating our working interest in each of our gross wells.

Principal Properties

Pinecrest operates in the Greater Red Earth, Alberta area with core properties located at Evi/Otter, Loon Red Earth and Ogston, all of which are reviewed in the Sproule Report. The following is a description of our principal oil and gas properties as at December 31, 2014.

Evi/Otter ("Evi") Properties

The Evi Properties are located in northern Alberta in townships 86-88, ranges 10-12 west of the fifth meridian. The Evi Properties consist of 131 (78.0 net) wells, of which 97 (54.9 net) oil wells are producing from either the Slave Point formation or the Granite Wash formation. Pinecrest operates 78 (66.0 net) wells, currently 52 (45.5 net) are producing. Pinecrest operates the majority of its production in this area and also operate the Evi 11-4-87-11W5M central battery. Field production is either gathered via effluent flow lines to the 11-4-87-11W5 battery or is trucked from single well batteries to the central battery where oil and water are separated, water is disposed of and oil and gas is shipped to sales.

Sproule assigned 2,541.3MBOE of Proved Reserves and 3,829.0 MBOE of P+P Reserves to the Evi/Otter Properties. Production from the properties for the year ended December 31, 2014 averaged 1,477 BOE/d net, 95% of which is light sweet crude oil(solution gas is conserved).

Red Earth Properties

The Red Earth Properties are located in northern Alberta in townships 87-89, ranges 8-9 west of the fifth meridian. The Red Earth Properties consist of 79 (45.6 net) wells, of which 42 (25.7 net) oil wells are producing from either the Slave Point formation or the Granite Wash formation. The Company operates a total of 44 (39.9 net) wells in Red Earth, of which 26 (24.0 net) oil wells are producing. Field production is either gathered via effluent flow lines to Pinecrest-operated or third party processing facilities or is trucked from single well batteries to either the Evi 11-04-87-11W5 battery or our Ogston 10-32-89-11W5M battery, or to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Sproule assigned 725.8 MBOE of Proved Reserves and 2,132.3 MBOE of P+P Reserves to the Red Earth properties. Production from the properties for the year ended December 31, 2014 averaged 340Bbls/d net, 100% of which is light sweet crude oil.

Loon Properties

The Loon Properties are located in northern Alberta in townships 84-86, range 9 west of the fifth meridian. The Loon Properties consist of 51 (15 net) wells, 13 (12.1 net) of which are operated by Pinecrest. Currently, 34 (10.8 net) oil wells are producing from either the Slave Point formation or from the Granite Wash formation. Field production is either gathered via effluent flow lines to Pinecrest-operated processing facilities or is trucked from single well batteries to the Evi 11-04-887-11W5 battery where oil and water are separated, water is disposed of and oil is shipped to sales.

Sproule assigned 475.9 MBOE of proved reserves and 632.6 MBOE of proved plus probable reserves to the Loon properties. Production from the properties for the year ended December 31, 2014 averaged 142 Bbls/d net, 100% of which is light sweet crude oil.

Item 6.2 Properties with No Attributable Reserves

Ogston Properties: The Ogston Properties are located in northern Alberta in townships 89-90, ranges 10-11 west of the fifth meridian. The Ogston Properties consist of 19 (12.3 net) wells, of which Pinecrest operates 14 (10.6 net) wells. Currently, no wells are producing Field production is gathered via effluent flow lines to the Ogston 10-32-89-11W5 central battery which Pinecrest operates and where oil and water are separated, water is disposed of and oil is trucked to sales.

Sproule did not assign any Reserves to the Ogston properties at December 31, 2014 due to economic conditions. Production from the properties for the year ended December 31, 2014 averaged 17 Bbls/d net, 100% of which is light sweet crude oil (solution gas is not conserved).

The following table sets out Pinecrest's developed and undeveloped land holdings as at December 31, 2014.

	DEVEOPED ACRES		UNDEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	20,320	13,527	151,942	148,385	172,262	161,862
Saskatchewan	-	-	971	971	971	971
Total	20,320	13,527	152,913	149,356	173,233	162,833

Rights to explore and develop 14,880 net acres of our undeveloped land holdings could expire by December 31, 2015 if not continued. At December 31, 2014, Pinecrest expensed a total of $17.7 million in land cost associated with 75,061 net acres that the Company has determined it will not develop.

The Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Item 6.3 Forward Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to fluctuations in commodity prices and foreign exchange rates. During the year ended December 31, 2013, Pinecrest had the following oil commodity price risk contracts in place:

TYPE	TERM	VOLUME (Bbl/d)	PRICEFLOOR[1] ($/Bbl)	PRICE CEILING[1] ($/Bbl)	INDEX
Swap	Jan 2014 – Dec 2014	500	$98.79 Cdn	$98.79 Cdn	WTI
Collar	Jan 2014 – Jun 2014	500	$95.00 Cdn	$109.50 Cdn	WTI

Note:

(1) Prices are weighted average for the term

Item 6.4 Additional Information Concerning Abandonment Costs

The Company estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2014, Pinecrest had 157 gross (82.9 net) well events for which it expects to incur abandonment costs.

Estimated costs of abandonment were included in the Sproule Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of Proved Reserves using forecast prices is $7.9 million undiscounted ($2.3 million using a 10% discount rate). The full amount of such values were deducted as abandonment costs in estimating future net revenue in respect of Proved Reserves as disclosed above. No allowance for salvage value was included in these costs. The total P+P abandonment costs are $9.3 million undiscounted and ($1.8 million discounted at 10%). The table below indicates the expected timing of our well abandonment costs.

The following table sets forth abandonment costs deducted in the estimation of our future net revenue:

Year	Total Proved (M$) [1]	Total P + P (M$) [1]
2015	205	95
2016	-	-
2017	11	114
2018	124	26
2019	15	84
Subtotal	355	319
Remainder	7,513	9,018
Total (Undiscounted)	7,868	9,337
Total discounted at 10%	2,283	1,781

Pinecrest expects to pay, in aggregate, abandonment costs of approximately $1.0 million over the next three financial years.

Item 6.7 Exploration and Development Activities

The following table sets forth the gross and net wells in which the Company participated during the year ended December 31, 2014:

	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil Wells	-	-	-	-	-	-
Gas Wells	-	-	-	-	-	-
Service Holes	-	-	-	-	-	-
Dry Holes	-	-	-	-	-	-
Stratigraphic Wells	-	-	-	-	-	-
Total	-	-	-	-	-	-

See "*Principal Properties*" for a description of our exploration and development during the twelve months ended December 31, 2014.

Item 6.8 Production Estimates The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained earlier under the subheading "*Disclosure of Reserves Data* ".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Total BOE (BOE/d)
Total Proved					
Evi	1,095	-	-	-	1,095
Red Earth	283	-	-	-	283
Loon	139	-	-	-	139
Total	1,517	-	-	-	1,517
Total Proved plus Probable					
Evi	1,145	-	-	-	1,145
Red Earth	366	-	-	-	366
Loon	142	-	-	-	142
Total	1,653	-	-	-	1,653

Item 6.9 Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	Quarter Ended 2014 (1)				Year Ended
	Dec. 31	Sep.30	Jun 30	Mar 31	Dec. 31 2014
Average Daily Production (2)					
Light and Medium Oil (Bbls/d)	1,775	1,688	1,916	2,033	1,852
Natural Gas (Mcf/d)	332	316	457	366	364
NGLs (Bbls/d)	52	68	78	49	63
Combined (BOE/d)	1,885	1,808	2,070	2,143	1,976
Average Production Prices Received					
Light and Medium Oil ($/Bbl)	74.75	96.12	103.69	99.16	93.73
Natural Gas ($/Mcf)	0.16	0.10	0.55	0.43	0.33
NGLs ($/Bbl)	11.19	13.34	9.19	16.58	12.20
Combined ($/BOE)	70.74	90.24	96.45	94.51	88.31
Royalties Paid					
Light and Medium Oil ($/Bbl)	14.82	19.35	20.50	14.90	17.35
Natural Gas ($/Mcf)	0.04	0.18	2.02	0.17	0.62
NGLs ($/Bbl)	3.71	11.08	7.34	10.74	8.19
Combined ($/BOE)	14.07	18.44	18.80	14.41	16.41
Transportation and Production Costs (3)(4)					
Light and Medium Oil ($/Bbl)	30.51	32.06	24.97	27.72	28.68
Natural Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Mcf)	-	-	-	-	-
Combined ($/BOE)	30.51	32.06	24.97	27.72	28.68
Netback Received (5)					
Light and Medium Oil ($/Bbl)	26.16	39.74	52.68	52.38	43.22
Natural Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Bbl)	-	-	-	-	-
Combined ($/BOE)	26.16	39.74	52.68	52.38	43.22

Notes:

(1) In providing information for each product type, allocation among multiple product types attributable to a single well has not been made. The principal product type attributable to the well has been used to categorize the well as either light and medium oil or gas.
(2) Before deduction of royalties.
(3) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil and natural gas wells. Pinecrest has allocated 100% of its operating costs to its oil wells, as approximately 100% of its production is from oil. Natural gas and NGL's is a by-product from producing the oil wells.
(4) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalties and transportation and production costs from revenues. Netbacks do not take into account commodity contracts that have been entered into during the period.
(6) The Company did not have any heavy oil (as defined in NI 51-101) production during the year ended December 31, 2014.

Production for the year ended December 31, 2014 was approximately 96% light and medium crude oil, 3% natural gas, and1% NGL's.

For the twelve months ended December 31, 2014, approximately 99% of Pinecrest's gross revenue was derived from light and medium oil production and less than 1% of our gross revenue was derived from natural gas and natural gas liquids production.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2014.

	Light and Medium Oil (Bbls/d)	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Evi	1,353	364	63	1477
Red Earth	340	-	-	340
Loon	142	-	-	142
Ogston	17	-	-	17
Total	1,852	364	63	1,976

SCHEDULE "A"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Pinecrest Energy Inc. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has:

(b) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(c) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(d) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(e) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(f) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(g) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED as of this 14th day of April, 2015.

(signed) "*Colin Witwer*"
Colin Witwer
Interim Chief Executive Officer

(signed) "*Howard Crone*"
Howard Crone
Director

(signed) "*Tracie Noble*"
Tracie Noble
Interim Chief Financial Officer

(signed) “*David Johnson*”
David Johnson
Director

SCHEDULE "B"

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Pinecrest Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)**			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	Evaluation of the P&NG Reserves of Pinecrest Energy Inc., As of December 31, 2013, prepared November 2014 to January 2015	Canada				
Total			**Nil**	**117,962**	**Nil**	**117,962**

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances after the effective date of our report(s).

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
January 7, 2015

Original Signed by Stephanie D. Brunt, P.Eng.

Stephane D Brunt, P. Eng.
Petroleum Engineer and Associate

Original Signed by Brian G. Trieber, P.L. (Geol.)

Brian G. Trieber, P.L. (Geol.)
Senior Geological Technologist and Partner

Original Signed by Nora T. Stewart, P. Eng.

Nora T. Stewart, P.Eng.
Vice-President, Canada and Partner