STANDARD EXPLORATION LTD.

Statement of Reserves Data and Other Oil and Gas Information
(NI 51-101F1)

Effective December 31, 2016

Dated April 25, 2017

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ABBREVIATIONS AND CONVERSION

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

Bbl barrel	Mcf thousand cubic feet
Mbbl thousand barrels	MMcf million cubic feet
MMbbl million barrels	Mcf/d thousand cubic feet per day
bbl/d barrels per day	MMBtu million British Thermal Units
NGLs natural gas liquids	Bcf billion cubic feet
boe/d barrels of oil equivalent per day	GJ gigajoule

AECO A natural gas storage facility located at Suffield, Alberta.

API American Petroleum Institute.

°API an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

boe barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 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.

Mcfe 1,000 cubic feet of gas equivalent.

MBOE 1,000 barrels of oil equivalent.

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.

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible 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.

“**Reserves**” are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

“**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.

“**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.
“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.

"**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 sub-divide 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 recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**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 + probable reserves. The following terms, used in the preparation of the Evaluator's Report (as defined herein) and this document have the following meanings:

"**Associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Company**" or "**Standard**" means Standard Exploration Ltd.

"**Crude oil**" or "**Oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and 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 the 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 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 defense, 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.

"**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**Field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

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

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

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer 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 paragraph (a).

"**Future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**Future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"**Gross**" means:

(a) in relation to the Company'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 Company;

(b) in relation to wells, the total number of wells in which the Company has an interest, and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"**Natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**Net**" means:

(a) in relation to the Company'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 the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**Non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**Operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**Property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**Property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**Proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**Reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**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.
"**Solution gas**" means natural gas dissolved in crude oil.

"**Stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type" if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“**Support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“**Unproved property**” means a property or part of a property to which no reserves have been specifically attributed.

“**Well abandonment costs**” means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

PART 1 - DATE OF STATEMENT

The effective date of the information being provided in this Form 51-101F1 is December 31, 2016 and is for the year ended December 31, 2016. The preparation date of the information being provided in this statement is March 8, 2017.

PART 2- DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Forecast Prices and Costs)

The reserves data set forth below (the "**Reserves Data**") is based upon a report prepared by GLJ Petroleum Consultants, independent petroleum consultants, Calgary, Alberta ("**GLJ**"), evaluating the crude oil, natural gas and natural gas liquids ("**NGL**") reserves of Standard, as at December 31, 2016, with a preparation date of dated March 8, 2017 (the "**GLJ Report**"). The Reserves Data summarizes the crude oil, NGL and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in 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 (the "**COGE Handbook**") and the reserve definitions contained in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators ("**NI 51-101**") and the COGE Handbook. Additional information not required by NI 51- 101 has been presented to provide continuity and additional information which Standard believes is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. 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 is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Company's crude oil, NGL 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. Readers should note that the totals in the following tables may not add due to rounding.

All properties evaluated are located in the Provinces of Alberta. **All monetary values are expressed in Canadian dollars, unless stated otherwise.**

SUMMARY OF OIL AND GAS RESERVES (Forecast Costs and Prices) as at December 31, 2016

RESERVES SUMMARY

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE (Forecast Costs and Prices) as at December 31, 2016

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserve Category	Company Gross (Mstb)	Company Net (Mstb)	Company Gross (Mstb)	Company Net (Mstb)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mstb)	Company Net (Mstb)	Company Gross (Mboe)	Company Net (Mboe)
Proved										
Producing	44	35	101	89	0	0	0	0	145	124
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	44	35	101	89	0	0	0	0	145	124
Total Probable	12	9	35	30	0	0	0	0	47	39
Total Proved Plus Probable	56	44	136	119	0	0	0	0	192	163

NET PRESENT VALUE SUMMARY

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOMES TAXES DISCOUNTED AT (%/YEAR) (FORECAST COSTS AND PRICES)

Reserves Category	0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Income Tax Discounted at 10%/year $/boe	$/Mcfe
Proved							
Producing	4,627	3,744	3,099	2,632	2,289	25.05	4.17
Developed Non-producing	0	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0	0
Total Proved	**4,627**	**3,744**	**3,099**	**2,632**	**2,289**	**25.05**	**4.17**
Total Probable	**2,041**	**1,140**	**691**	**455**	**321**	**17.55**	**2.92**
Total Proved Plus Probable	**6,667**	**4,884**	**3,789**	**3,087**	**2,610**	**23.24**	**3.87**

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/YEAR) (FORECAST COSTS AND PRICES)

Reserves Category	0% M$	5% M$	10% M$	15% M$	20% M$
Proved Producing	4,627	3,744	3,099	2,632	2,289
Proved Developed (Non-producing)	0	0	0	0	0
Proved (Undeveloped)	0	0	0	0	0
Total Proved	**4,627**	**3,744**	**3,099**	**2,632**	**2,289**
Total Probable	**2,041**	**1,140**	**691**	**455**	**321**
Total Proved Plus Probable	**6,667**	**4,884**	**3,789**	**3,087**	**2,610**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

Reserves Category	Revenue M$	Royalties M$	Operating Costs M$	Capital Development Costs M$	Abandonment Costs M$	Future Net Revenue Before Income Taxes M$	Income Tax M$	Future Net Revenue After Income Taxes M$
Proved Producing	9,739	1,397	3,272	0	443	4,627	-	4,627
Proved Developed (Non-producing)	0	0	0	0	0	0	-	0
Proved (Undeveloped)	0	0	0	0	0	0	-	0
Total Proved	**9,739**	**1,397**	**3,272**	**0**	**443**	**4,627**	**0**	**4,627**
Total Probable	**4,162**	**637**	**1,438**	**0**	**47**	**2,041**	**0**	**2,041**
Total Proved Plus Probable	**13,901**	**2,034**	**4,711**	**0**	**489**	**6,667**	**0**	**6,667**

FUTURE NET REVENUE BY PRODUCTION GROUP
Future Net Revenue Before Income Taxes [3]
(Discounted at 10% per year)

	M$	$/boe	$/Mcfe
Proved Producing			
Light & Medium Oil [1]	717	20.36	3.39
Heavy Oil [1]	2,382	26.91	4.49
Natural Gas [2]	0	0.00	0.00
Total: Proved Producing	**3,099**	**25.05**	**4.17**
Total Proved			
Light & Medium Oil [1]	717	20.36	3.39
Heavy Oil [1]	2,382	26.91	4.49
Natural Gas [2]	0	0.00	0.00
Total: Total Proved	**3,099**	**25.05**	**4.17**
Total Proved Plus Probable			
Light & Medium Oil [1]	849	19.11	3.18
Heavy Oil [1]	2,940	24.78	4.13
Natural Gas [2]	0	0	0
Total: Total Proved Plus Probable	**3,789**	**23.24**	**3.87**

Notes:
1. Including solution gas and other by-products
2. Including by-products but excluding solution gas
3. Unit values are based on Company Net Reserves

PART 3 - PRICING ASSUMPTIONS

The following pricing assumptions were provided by GLJ, a qualified reserves evaluator independent of the Company.

3.1 Forecast Prices used in Estimates

Oil and Liquids Forecast – January 1, 2017

Table 1

GLJ Petroleum Consultants

Crude Oil and Natural Gas Liquids

Price Forecast

Effective January 1, 2017

Year	Inflation %	CADUSD Exchange Rate USD/CAD	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Constant 2017 $ USD/bbl	NYMEX WTI Near Month Contract Crude Oil at Cushing, OK Then Current USD/bbl	ICE Brent Near Month Contract Crude Oil FOB North Sea Then Current USD/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current CAD/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	WCS Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current CAD/bbl	Light Sour Crude Oil (35 API, 1.2%S) at Cromer Then Current CAD/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Butane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton C5+ Stream Quality CAD/bbl
2007	2.1	0.9352	85.35	72.39	72.71	77.06	53.64	52.38	43.42	71.13	65.71	N/A	49.56	61.78	77.38
2008	2.4	0.9428	114.99	99.64	98.30	102.90	84.31	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.8798	69.60	61.78	62.50	66.32	60.18	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.9711	89.25	79.52	80.25	77.87	68.45	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.0115	104.91	95.12	110.86	95.53	78.59	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012	1.5	1.0009	100.94	94.21	111.71	86.60	74.42	73.13	63.64	84.51	81.37	N/A	29.04	66.70	100.84
2013	0.9	0.9711	103.41	97.96	108.77	93.47	76.33	75.01	65.11	92.30	88.13	N/A	38.88	68.81	104.70
2014	1.9	0.9055	97.24	93.00	99.71	94.58	81.08	81.03	73.73	92.68	89.67	N/A	45.53	69.20	102.44
2015	1.1	0.7831	50.04	48.78	53.60	57.20	45.50	44.82	39.25	55.49	51.87	N/A	6.49	36.75	60.42
2016	1.5	0.755	43.93	43.30	45.01	52.95	39.71	38.84	32.66	51.34	48.71	N/A	13.03	34.36	56.12
2017 Q1	2.0	0.750	54.00	54.00	56.00	68.00	52.70	52.02	45.41	66.64	63.24	11.48	29.24	48.96	70.72
2017 Q2	2.0	0.750	54.00	54.00	56.00	68.00	52.70	52.02	45.41	66.64	63.24	10.99	26.52	48.96	70.72
2017 Q3	2.0	0.750	56.00	56.00	58.00	70.67	55.33	54.63	47.96	69.25	65.72	10.99	27.56	50.88	73.49
2017 Q4	2.0	0.750	56.00	56.00	58.00	70.67	55.33	54.63	47.96	69.25	65.72	11.15	30.39	50.88	73.49
2017 Full Year	2.0	0.750	55.00	55.00	57.00	69.33	54.02	53.32	46.69	67.95	64.48	11.15	28.43	49.92	72.11
2018	2.0	0.775	57.84	59.00	61.00	72.26	57.52	56.79	50.40	70.81	67.20	9.92	26.74	54.19	74.79
2019	2.0	0.800	61.51	64.00	66.00	75.00	62.02	61.27	55.03	73.50	69.75	10.52	26.25	56.25	78.75
2020	2.0	0.825	63.14	67.00	70.00	76.36	63.76	63.00	56.96	74.84	71.02	11.27	26.73	57.27	79.80
2021	2.0	0.850	65.59	71.00	74.00	78.82	66.68	65.90	59.95	77.25	73.31	11.87	27.59	59.12	82.37
2022	2.0	0.850	67.02	74.00	77.00	82.35	70.25	69.42	63.43	80.71	76.59	12.54	28.82	61.76	86.06
2023	2.0	0.850	68.37	77.00	80.00	85.88	73.77	72.91	66.99	84.16	79.87	13.20	30.06	64.41	89.32
2024	2.0	0.850	69.64	80.00	83.00	89.41	77.34	76.45	70.48	87.62	83.15	13.56	31.29	67.06	92.99
2025	2.0	0.850	70.84	83.00	86.00	92.94	80.86	79.93	73.63	91.08	86.44	13.83	32.53	69.71	97.59
2026	2.0	0.850	72.00	86.05	89.64	95.61	84.43	83.47	77.54	93.70	88.92	14.13	33.46	71.71	99.91
2027+	2.0	0.850	72.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

A historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

Revised 2016-12-31

PART 4 - RECONCILIATION OF CHANGES IN RESERVES

4.1 Reserves Reconciliation

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at December 31, 2016, against such reserves as at December 31, 2015 (summarized in the tables above) based on the forecast price and cost assumptions evaluated in accordance with NI 51-101 definitions:

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2015	156.0	45.0	201.0	38.0	9.0	47.0	118.0	37.0	155.0	0	0	0
Discoveries, Extensions and Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	(1)	(1)	0	0	0
Technical Revisions	15.0	(9)	7.0	9.0	3	12.0	2	(1)	1.0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Production	(26.0)	0	(26.0)	(4.0)	0	(4.0)	(20.0)	0	(20.0)	0	0	0
December 31, 2016	145.0	36.0	181.0	44.0	12.0	55.0	101.0	35.0	136.0	0	0	0

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2015	0	0	0	0	0	0	0	0	0	156.0	46.0	202.0
Discoveries, Extensions and Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	11.0	1	12.0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	(23.0)	0	(23.0)
December 31, 2016	0	0	0	0	0	0	0	0	0	144.0	47.0	191.0

See section 5.1 for the written description of reasons for the Technical Revisions to the Reserves

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

PART 5 - ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

The following discussion generally describes the basis on which Standard attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

5.1.1 Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill-drilling locations. The majority of these reserves are planned to be on stream within a two-year timeframe.

SUMMARY OF PROVED UNDEVELOPED RESERVES (Forecast Prices & Costs)

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		BOE	
Year	Attributed (Mbbl)*	Current Total (Mbbl)	Attributed (Mbbl)	Current Total (Mbbl)	Attributed (MMcf)	Current Total (MMcf)	Attributed (Mbbl)	Current Total (Mbbl)	Attributed (Mboe)	Current Total (Mboe)
2015-12-31	0	0	0	0	0	0	0	0	0	0
2016-12-31	0	0	0	0	0	0	0	0	0	0

5.1.2 Probable Reserves

Probable reserves are generally reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two-year timeframe. All probable reserves in the GLJ Report relate to proved projects (i.e. higher recovery assumptions).

SUMMARY OF PROBABLE UNDEVELOPED RESERVES (Forecast Prices & Costs)

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		BOE	
Year	Attributed (Mbbl)*	Current Total (Mbbl)	Attributed (Mbbl)	Current Total (Mbbl)	Attributed (MMcf)	Current Total (MMcf)	Attributed (Mbbl)	Current Total (Mbbl)	Attributed (Mboe)	Current Total (Mboe)
2015-12-31	0.0	0.0	0	0	0	0	0	0	0	0
2016-12-31	0	0	0	0	0	0	0	0	0	0

5.2 Significant Factors or Uncertainties

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company. Some of these risks are noted below.

The process of estimating reserves is complex. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. 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 natural gas prices and costs change. Estimates are reviewed and revised, either upward or downward, as warranted by newly acquired information.

The evaluation and drilling of hydrocarbon targets may be curtailed, delayed or cancelled by the unavailability or prevailing cost of drilling rigs or technical contractors, mechanical difficulties, adverse weather and ocean conditions, environmental issues, political or social unrest, technical hazards, such as unusual or unexpected formations or pressures or because of issues related to compliance with government regulations or requirements. Drilling may result in unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some hydrocarbons, are not sufficiently productive to economically justify commercial development. Furthermore, the successful completion of a well does not assure a profit on investment or the recovery of drilling, completion and operating costs.

5.3 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 Company's future net revenues of the reserves evaluated in the GLJ Report for the year ended December 31, 2016.

Future Development Costs
Estimated Using Forecast Prices and Costs (Undiscounted)

	Year				
Reserve Category	**2017**	**2018**	**2019**	**2020**	**2021 +**
Proved Producing	0	0	0	0	0
Total Proved	0	0	0	0	0
Total Proved + Probable	0	0	0	0	0

PART 6
OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2016, all of which were in Alberta.

	Oil		Natural Gas	
	Gross (1)	**Net (2)**	**Gross (1)**	**Net (2)**
Chin Coulee, AB Area				
Producing	3	3	0	0
Non-producing	1	1	0	0
Claresholm, AB Area	2	2	0	0
Crossfield, AB Area				
Producing	0	0	0	0
Non-producing	0	0	1	.25
Taber, AB Area				
Producing	0	0	0	0
Non-producing	0	0	2	1
Berry Creek, AB Area				
Producing	0	0	1	0.25
Non-producing	0	0	0	0
Provost, AB Area				
Producing	1	0.25	0	0
Non-producing	0	0	1	0.25
Total:	5	4.25	5	1.75

Notes:

(1) "Gross" wells mean the number of wells in which Standard has a working interest or a royalty interest that may be converted into a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Standard percentage working interest therein.

The following is a description of Standard's important properties as of December 31, 2016.

Chin Coulee, Alberta

The Chin Coulee property is located in Township 007, Range 15 W4M. In Chin Coulee, the Company holds a 100% working interest in 256 gross (256 net) hectares of developed land in the Chin Coulee area of Alberta. These petroleum and natural gas interests contain a total of 4 gross (4 net) operated wells (3 producing and 1 non-producing).

Production from this property averaged 53 barrels of oil equivalent per day gross (53 net) at December 31, 2016 (company fiscal year-end).

Claresholm, Alberta

The Claresholm property is located in Township 013, Ranges 24 and 25W4M. At Claresholm the Company owns a 100% working interest in 128 gross (128 net) hectares of developed land, which contain 2 wells producing medium gravity oil from the Upper Cretaceous Barons formation. Production from this property averaged 9 bopd at December 31, 2016. In addition, the Company holds a 100% working interest in approximately 700 hectares of undeveloped lands.

Crossfield, Alberta

The Crossfield property is located in Township 028, Range 01 W5M. The Company has a 25.0% working interest in 256 gross (64 net) hectares of developed land and 1 well in the Crossfield area of Alberta.

Taber North, Alberta

The Taber North property is located in Township 10, Range 15 W4M. In Taber North, Alberta, the Company has a 50% working interest in 256 gross (128 net) hectares of developed land and 1 well.

6.2 Properties With No Attributed Reserves

The Company has an interest in 3,425.5 gross and 3,161.5 net hectares of undeveloped lands as at December 31, 2016. The undeveloped lands have no work commitments and the Corporation is reviewing viable opportunities.

PROPERTY	GROSS (HA)	NET (HA)
Chin Coulee	512	512
Crossfield	352	88
Taber North	128	128
Stanmore	256	256
Claresholm/ Keho Lake	1664	1664
Hardy, Saskatchewan	1536	1536
Other	385.5	385.5
TOTALS	**4833.5**	**4569.5**

6.3 Forward Contracts

The Company does not have any forward sales contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company performs an annual review of its forecast abandonment and site reclamation ("Abandonment") costs. These costs are estimated utilizing the Alberta Energy and Utilities Board's Abandonment and liability calculation spreadsheet as a basis, but the Company's review is further augmented with adjustments on an individual well and facility basis. The review considers the following factors in assessing liability: well depth, nature of the production stream, the nature, location and condition of the surface lease, age of the well and/or facility, number of zones to be abandoned, and presence of salvageable equipment such as tanks, tubing, and rods. The Abandonment cost determined is net of salvage.

Total abandonment costs are included in the reserves data summarized as follows:

Company Annual Abandonment Expenditures (M$) Forecast Pricing as at December 31, 2016				
YEAR		**PROVED PRODUCING**	**TOTAL PROVED**	**TOTAL PROVED PLUS PROBABLE**
2015		0	0	0
2016		0	0	0
2017		0	0	0
2018		0	0	0
2019		0	0	0
2020		0	0	0
2021		0	72	72
2022		72	0	0
2023		0	0	0
2024		0	0	0
2025		0	0	0
2026		0	0	0
Sub-total		72	72	72
Remainder		371	366	415
TOTAL		443	438	487
10% DISCOUNTED		91	93	77

6.5 **Tax Horizon**

Based on the after tax economic forecasts prepared by GLJ, income taxes will not be payable by the Company in the total proved plus probable reserves category.

6.6 **Costs Incurred**

The following table summarizes the capital expenditures related to the Company's activities for the year ended December 31, 2016 related to exploration, development, and evaluation expenditures and property and equipment:

	Property Acquisition Costs			
	Proved Properties ($)	Unproved Properties ($)	Exploration Costs ($)	Development Costs ($)
CANADA	**Nil**	**Nil**	**Nil**	**Nil**

The Company has no interests in or expenditures for non-conventional oil and gas properties.

6.7 Exploration and Development Activities

The following table sets forth the number of wells in which the Company drilled during the year.

	Exploratory Wells		**Development Wells**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Oil Wells	-	-	0	0
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	0	0
Total Wells	-	-	0	0

Note:

(1) "Gross Wells" are the total number of wells in which the Corporation has an interest.

(2) "Net Wells" are the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells.

The Company will continue to develop its lands in Alberta where Standard operates its activities.

6.8 Production Estimates

The following table discloses for each product type the total volume of production estimated by GLJ for 2017 in the estimates of future net revenue from the forecast case of proved plus probable reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

SUMMARY OF FIRST YEAR PRODUCTION AND OIL AND GAS RESERVES
2017AVERAGE DAILY PRODUCTION

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Entity Description	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross mcf/d	Company Net mcf/d	Company Gross bbl/d	Company Net bbl/d	Company Gross boe/d	Company Net boe/d
Proved Producing										
Chin Coulee	0	0	45	39	0	0	0	0	45	39
Claresholm	10	8	0	0	0	0	0	0	10	8
Total: Proved Producing	**10**	**8**	**45**	**39**	**0**	**0**	**0**	**0**	**55**	**47**
Proved Developed Nonproducing										
Chin Coulee	0	0	0	0	0	0	0	0	0	0
Claresholm	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Total: Proved Developed Nonproducing	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Proved Undeveloped										
Chin Coulee	0	0	0	0	0	0	0	0	0	0
Claresholm	0	0	0	0	0	0	0	0	0	0
Total: Proved Undeveloped	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Proved										
Chin Coulee	0	0	45	39	0	0	0	0	45	39
Claresholm	10	8	0	0	0	0	0	0	9	8
Total: Total Proved	**10**	**8**	**45**	**39**	**0**	**0**	**0**	**0**	**55**	**47**
Total Probable										
Chin Coulee	0	0	1	0	0	0	0	0	1	0
Claresholm	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Total: Total Probable	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**1**	**1**
Total Proved Plus Probable										
Chin Coulee	0	0	46	40	0	0	0	0	46	40
Claresholm	9	8	0	0	0	0	0	0	10	8
Total: Total Proved Plus Probable	**10**	**8**	**46**	**40**	**0**	**0**	**0**	**0**	**56**	**48**

6.9 Production History

The following tables 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:

Average Daily Production and Prices by Quarter

	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Production				
Oil (bbl/d)	62	62	65	67
Natural gas (mcf/d)	-	11	6	4
NGL (bbl/d)	-	-	-	-
Boe/d	62	64	66	68
Average Prices				
Oil ($/bbl)	46.82	40.46	40.89	25.74
Natural gas ($/mcf)	-	-	-	-
NGL ($/bbl)	-	-	-	-
$/boe	46.82	40.46	40.89	25.74

Royalties

	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Royalties ($)	30,791	29,188	21,344	15,291
Royalties ($/boe)	5.40	4.94	3.55	2.48
Royalties Rate (% of revenue)	12	12	9	10

Operating Costs

Operating costs can vary significantly depending on such factors as production rates, reservoir quality, water content and available infrastructure.

	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Operating expense ($)	(45,241)	71,306	113,882	71,399
$/boe	(7.93)	12.06	18.97	11.62
Percent of revenue (%)	(17)	30	46	45

Netbacks

($/boe except for production)	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Production *(boe/d)*	62	64	66	68
Revenue	46.82	40.46	40.89	25.74
Royalties	(5.40)	(4.94)	(3.55)	(2.48)
Operating Expense	7.93	(12.06)	(18.97)	(11.62)
Operating Netback	49.36	23.46	18.37	11.64
G & A Expense	(30.29)	(25.34)	(27.46)	(22.59)
Interest and other	0.34	0.24	0.24	0.19
Corporate Netback	19.41	(1.64)	(8.85)	(10.76)

Production Volume by Field

The following table discloses for each important field and in total, the Company's production volume for the year ended December 31, 2016 for each product type:

Field	**Oil & NGL bbl/d**	**Natural Gas Mcf/d**	**Total boe/d**
Chin Coulee	53	-	53
Claresholm	9	-	9
Total	62	-	62