PETROX RESOURCES CORP.
(“Petrox”)

<u>STATEMENT OF RESERVES DATA</u>
<u>AND OTHER OIL AND GAS INFORMATION</u>

March 23, 2017

PETROX RESOURCES CORP.
("Petrox")

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

This Statement of Reserves Data and Other Oil and Gas Information in Form 51-101F is provided in accordance with NI 51-101. Attached as Appendices to this statement are the following documents derived from and prepared in accordance with, NI 51-101:

(a) Form 51-101F2 – "Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor" by DeGolyer and MacNaughton Canada Limited, dated March 6, 2017 (Appendix "A"); and

(b) Form 51-101F3 – "Report of Management and Directors on Oil and Gas Disclosure" dated March 23, 2017 (Appendix "B").

Petrox commissioned a report (the "**DMCL Report**") from DeGolyer and MacNaughton Canada Limited ("**DMCL**"), which appraises Petrox's oil and gas assets for the estimates of the extent of the proved, probable, and possible light/medium crude oil and sales gas reserves and the estimates of the value of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in Petrox's Bashaw property located in Alberta, Canada (the "**Bashaw Assets**") and Petrox's Fletwode property (the "**Fletwode Assets**") located in Saskatchewan. The Bashaw Assets and the Fletwode Assets shall be collectively referred to herein as the "**Properties**". The following is a summary of the reserves data and other oil and gas information with respect to the Properties dated effective December 31, 2016 taken from the DMCL Report.

Classification of Reserves

Petroleum reserves included in this summary are classified by degree of proof as proved, probable, or possible. For purposes of this summary, reserves are those quantities of oil or gas anticipated to be economically recoverable from known accumulations. The definitions of reserves shown below serve as the basis for the estimates contained herein. The definitions are in accordance with those prepared for National Instrument 51-101 as presented in the Canadian Oil and Gas Evaluation Handbook Second Edition September 1, 2007, Volume 1 Reserves Definitions and Evaluation Practices and Procedures ("**COGEH**"), Section 5. The petroleum reserves are classified in accordance with Sections 5.4.1, 5.4.2, and 5.4.3 of COGEH.

Reserves Categories

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- 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 – 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.

Probable 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 + probable reserves.

Possible Reserves – Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Development and Production Status – Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves – Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and nonproducing.

Developed Producing 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 Nonproducing Reserves – Developed nonproducing 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 – 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 category (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.

Levels of Certainty for Reported Reserves – qualitative certainty levels contained in the definitions in the reserves categories above are applicable to individual reserves 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 reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves,

- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves,

- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

A quantitative 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 are 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.

Estimation of Reserves

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Where appropriate, the volumetric method was used to estimate the petroleum initially in place ("**PIIP**"). Petroleum is defined as a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid, or solid phase. Structural maps were prepared to delineate each reservoir, and net pay maps were constructed to estimate reservoir volumes. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. All pertinent reservoir data, including drill-stem tests, production tests, reservoir fluid analyses, and bottom hole pressure and temperature data, were used to determine the volume of productive reservoir rock, reservoir fluid characteristics, and the volumes of PIIP. The test results contained in the DMCL Report are not necessarily indicative of long-term performance or ultimate recovery.

Where appropriate, estimates of ultimate recovery were obtained after applying recovery factors to PIIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors. In such cases, an analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production decline curves, reserves were estimated only to the limits of economic production based on current economic conditions.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Where applicable the reserves estimates presented herein are generally based on consideration of monthly and cumulative production data through December 31, 2016.

Gas volumes estimated herein are reported as wet gas, marketable gas and sales gas expressed at a temperature base of 60 degrees Fahrenheit and a press base of 14.65 pounds per square inch absolute ("**psia**"). Wet gas is defined as the total has to be produced before forecast reduction for volume loss due to fuel and flare consumption and before forecast reduction for liquids removal. Marketable gas is defined as wet gas available for delivery to the pipeline after reduction for liquids removal during gas processing and other shrinkage. Sales gas is defined as marketable gas after reduction for estimated fuel usage. Estimates of gas reserves and volumes are converted from cubic meters and expressed in millions of cubic feet ("**MMcf**").

In this summary, the barrels of oil equivalent (BOE) conversion ratio of 6 Mcf of gas per 1 barrel of oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and may not represent a value equivalency at the wellhead.

Crude oil volumes estimated herein are those to be recovered by normal field separation. Sales oil volumes estimated herein are those to be recovered by passage through field, platform, and onshore separation. Estimates of oil are expressed in barrels ("**bbl**"). In these estimates, 1 barrel equals 42 U.S. gallons.

Proved developed reserves estimates are based on performance analysis of current wells. Total proved reserves include the proved developed reserves plus proved undeveloped reserves associated with certain planned wells that are forecast to be drilled in proved reserves areas. A portion of the estimated probable reserves is attributable to production performance improvements and a portion is associated with the drilling of wells for opportunities of less certainty than those estimated to be proved. Estimates of possible reserves include further production performance improvements beyond those associated with probable reserves classification.

Valuation of Reserves

Revenue values in this summary have been prepared using initial prices and costs and future price and cost assumptions specified by Petrox. A Forecast Price Case was evaluated using future prices that vary from current prices as well as escalations in operating expenses and capital and abandonment costs. Reserves estimates herein are based on the Forecast Price Case assumptions.

In this summary, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves are based on projections of estimated future production and revenue prepared for the Properties. Probable and possible reserves involve substantially higher risks than proved reserves.

1. DATE OF STATEMENT

1.1 Relevant Dates:

Statement Date: March 23, 2017

Effective Date: December 31, 2016

Preparation Date: March 23, 2017

2. DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Forecast Price Case)

2.1.1. Breakdown of Reserves (Forecast Prices and Costs)

The estimated Forecast Price Case company gross and net proved, probable, and possible reserves for the Forecast Price Case, as of December 31, 2016 of the Properties are summarized as follows, expressed in thousands of barrels ("**Mbbl**") for oil and NGL and millions of cubic feet ("**MMcf**") for sales gas:

TOTAL COMPANY – FORECAST PRICE CASE								
	Remaining Reserves as of December 31, 2016							
	Light & Medium Crude Oil		Heavy Crude Oil		Natural Gas		NGL	
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl
Proved Developed								
Producing	50	48	-	-	-	-	-	-
Non-Producing	22	18	-	-	26	22	-	-
Proved Undeveloped	51	46	-	-	-	-	-	-
Total Proved	123	112	-	-	26	22	-	-
Probable	116	95	-	-	108	88	-	-
Total Proved + Probable	239	207	-	-	134	110	-	-
Possible	96	79	-	-	88	72	-	-
Total	335	286	-	-	222	182	-	-

The proved-plus-probable-plus-possible revenue is an arithmetic sum of multiple estimates of revenue, which statistical principles indicate may be misleading as to value that may actually be recovered. Attention should be given to the estimates of individual classes of reserves and their probability of occurrence as described in the Reserves Categories section above.

2.1.2. Net Present Value of Future Net Revenue (Forecast Case)

Based on the Forecast Price Case described herein, estimated future net revenue and net present value of future net revenue before and after income tax attributable to the Properties in the total proved developed, proved-plus-probable, and proved-plus-probable-plus-possible reserves are summarized in the following two tables, expressed in thousands of Canadian dollars (M$):

TOTAL COMPANY	COMPANY SHARE – FORECAST PRICE CASE				
	Future Net Revenue Before Income Tax as of December 31, 2016				
		Discounted			
Reserve Category	Undiscounted	at 5%	at 10%	at 15%	at 20%
	M$	M$	M$	M$	M$
Proved Developed					
Producing	718	704	678	648	617
Non-Producing	322	275	235	201	172
Proved Undeveloped	179	31	(94)	(195)	(275)
Total Proved	1,219	1,010	819	654	514
Probable	4,054	3,037	2,318	1,801	1,423
Total Proved + Probable	5,273	4,047	3,137	2,455	1,937
Possible	4652	2,953	1,976	1,386	1,012
Total	9,925	7,000	5,113	3,841	2,949

TOTAL COMPANY	COMPANY SHARE – FORECAST PRICE CASE				
	Future Net Revenue After Income Tax as of December 31, 2016				
		Discounted			
Reserve Category	Undiscounted	at 5%	at 10%	at 15%	at 20%
	M$	M$	M$	M$	M$
Proved Developed					
Producing	718	704	678	648	617
Non-Producing	322	275	235	201	172
Proved Undeveloped	179	31	(94)	(195)	(275)
Total Proved	1,219	1,010	819	654	514
Probable	3,381	2,553	1,961	1,532	1,218
Total Proved + Probable	4,600	3,563	2,780	2,186	1,732
Possible	3,418	2,176	1,461	1,030	755
Total	8,018	5,739	4,241	3,216	2,487

The proved-plus-probable-plus-possible revenue is an arithmetic sum of multiple estimates of revenue, which statistical principles indicate may be misleading as to value that may actually be returned. Attention should be given to the estimates of individual classes of reserves and their probability of occurrence as described in the Reserves Categories section above.

The following table sets out, by product type, in each case with associated by-products and on a unit value basis for each product type, in each case with associated by-products, the net present value of future net revenue before deducting future income tax expenses estimated using forecast prices and costs and calculated using a discount rate of 10 percent:

2.1.3. Additional Information Concerning Future Net Revenue (Forecast Case)

Based on the Forecast Price Case described herein, estimated future net revenue and net present value at various discount rates are summarized as follows, expressed in thousands of Canadian dollars (M$):

TOTAL COMPANY	**FORECAST PRICE CASE**				
	Proved Developed Producing (M$)	**Proved Developed (M$)**	**Total Proved (M$)**	**Proved Plus Probable (M$)**	**Proved Plus Probable Plus Possible (M$)**
Future Gross Revenue	3,416	5,068	8,785	18,493	27,605
Royalties	183	500	976	2,752	4,399
Operating Expenses	2,149	2,760	4,221	7,118	9,900
Processing and Other Income	-	-	-	-	-
Capital Costs	-	337	1,837	2,719	2,719
Abandonment Costs	365	431	531	631	663
Future Net Revenues Before Future Income Tax	718	1,040	1,219	5,273	9,925
Future Income Tax	-	-	-	673	1,906
Future Net Revenues After Future Income Tax	718	1,040	1,219	4,600	8,018
Net Present Value at 5%	704	979	1,010	3,563	5,739
Net Present Value at 10%	678	913	819	2,780	4,241
Net Present Value at 15%	648	849	654	2,186	3,216
Net Present Value at 20%	617	789	514	1,732	2,487

Note: The numbers in this table may not exactly add due to rounding.

The proved-plus-probable-plus-possible revenue is an arithmetic sum of multiple estimates of revenue, which statistical principles indicate may be misleading as to value that may actually be returned. Attention should be given to the estimates of individual classes of reserves and their probability of occurrence as described in the Reserves Categories section above.

Proved, probable, and possible reserves have been estimated only for known accumulations and do not include any exploration potential. Reserves estimates herein are based on forecast prices and costs.

The following table sets out by product type, in each case with associated by-products, and on a unit value basis for each product type, in each case with associated by-products, the net present value of future net revenue (before deducting future income tax expenses) estimated using forecast prices and costs and calculated using a discount rate of 10 percent:

RESERVES CATEGORY	PRODUCTION GROUP	BFIT Future Net Revenue Discounted (10%/Yr)(1)	UNIT VALUE (1)
		(M$)	($/BOE)
Proved	Bitumen		
	Coal Bed Methane		
	Conventional Natural gas (excluding gas and by-products from oil wells)		
	Gas Hydrates		
	Heavy Crude Oil (including solution ga)		
	Light Crude Oil and Medium Crude Oil (including solution gas)	819	7.09
	Natural Ga Liquids		
	Shale Gas		
	Synthetic Crude Oil		
	Synthetic Gas		
	Tight Oil		
	TOTAL	819	7.09
Proved + Probable	Bitumen		
	Coal Bed Methane		
	Conventional Natural gas (excluding gas and by-products from oil wells)		
	Gas Hydrates		
	Heavy Crude Oil (including solution gas)		
	Light Crude Oil and Medium Crude Oil (including solution gas)	3,137	13.93
	Natural Ga Liquids		
	Shale Gas		
	Synthetic Crude Oil		
	Synthetic Gas		
	Tight Oil		
	TOTAL	3,137	13.93
Proved + Probable + Possible	Bitumen		
	Coal Bed Methane		
	Conventional Natural gas (excluding gas and by-products from oil wells)		
	Gas Hydrates		
	Heavy Crude Oil (including solution gas)		
	Light Crude Oil and Medium Crude Oil (including solution)	5,113	16.16
	Natural Ga Liquids		
	Shale Gas		
	Synthetic Crude Oil		
	Synthetic Gas		
	Tight Oil		
	TOTAL	5,113	16.16

Notes:
(1) The unit values are based on net reserve volumes before income tax ("**BFIT**")

(2) The numbers in this table may not add exactly due to rounding.

3. PRICING ASSUMPTIONS

3.1 Forecast Prices Used in Estimates

The following assumptions were used in estimating future net revenue in the Forecast Price Case:

Prices – Light/Medium oil and gas prices used in the DMCL Report were based on the DeGolyer and MacNaughton Canada Limited price forecast. These prices were forecast into the future and are attached hereto. These prices have been adjusted for transportation differentials and quality in the property based on the lease operating statements provided by Petrox and DMCL's experience with similar operations.

Operating Expenses – Operating expenses and operating-expense forecasts have been determined by DMCL based on the lease operating statements provided by Petrox and DMCL's experience with similar operations. In certain situations, future expenses, either higher or lower than current expenses, may have been used because of anticipated changes in operating conditions. Escalation has been applied to operating expenses to account for inflation.

Abandonment Costs – Gross abandonment costs were estimated for each property. These costs were projected to occur in the last year of economic production of each reserves entity and for non-reserves wells two years from the effective date of the DMCL Report.

Capital Costs – Future capital costs were estimated using current capital cost forecasts provided by Petrox. Where necessary, these costs were scaled and adjusted to fit the scenario being evaluated. Escalation has been applied to capital costs to account for inflation.

Royalties – The Properties are subject to various applicable Canadian royalties.

Taxes – The Properties are subject to Canadian corporation tax. At the request of Petrox, DMCL assessed Canadian federal and provincial corporation taxes on a consolidated basis taking into account the tax basis of the properties as of December 31, 2016.

4. RECONCILIATION OF CHANGES IN RESERVES

4.1 Reserves Reconciliation

The following reconciliation is provided in respect of reserves estimated using forecast prices and costs.

	Total Oil (MBBL)	Light/Med Oil (MBBL)	Heavy Oil (MBBL)	Sales Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
TOTAL PROVED						
Opening Balance (Dec 31, 2014)	128	128	-	27	-	133
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(1)	12	12	-	-	-	12
Discoveries	-	-	-	-	-	-
Acquisitions(2)	-	-	-	-	-	-
Dispositions(2)	-	-	-	-	-	-
Economic Factors(3)	(6)	(6)	-	(1)	-	(6)
Production	(11)	(11)	-	-	-	(11)
Closing Balance (Dec 31, 2015)	123	123	-	26	-	127
TOTAL PROBABLE						
Opening Balance (Dec 31, 2014)	121	121	-	109	-	150
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(1)	(2)	(2)	-	-	-	(2)
Discoveries	-	-	-	-	-	-
Acquisitions(2)	-	-	-	-	-	-
Dispositions(2)	-	-	-	-	-	-
Economic Factors(3)	(3)	(3)	-	(1)	-	(3)
Production	-	-	-	-	-	-
Closing Balance (Dec 31, 2015)	116	116	-	108	-	145

TOTAL PROVED + PROBABLE

Opening Balance (Dec 31, 2014)	249	249	-	136	-	283
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[1]	10	10	-	0	-	10
Discoveries	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-
Dispositions[2]	-	-	-	-	-	-
Economic Factors[3]	(9)	(9)	-	(2)	-	(9)
Production	(11)	(11)	-	-	-	(11)
Closing Balance (Dec 31, 2015)	239	239	-	134	-	272

TOTAL PROVED + PROB + POS

Opening Balance (Dec 31, 2014)	348	348	-	227	-	400
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[1]	10	10	-	-	-	10
Discoveries	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-
Dispositions[2]	-	-	-	-	-	-
Economic Factors[3]	(12)	(12)	-	(5)	-	(13)
Production	(11)	(11)	-	-	-	(11)
Closing Balance (Dec 31, 2015)	335	335	-	222	-	386

The numbers in this table may not exactly add due to rounding.

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes and working interest changes resulting from timing and interest reversions.

(2) Includes production attributable to any acquired interests from the acquisition date to the effective date of the DMCL Report and production realized from disposed interests from the opening balance date to the effective date of disposition.

(3) Includes economic revisions related to price, royalty factor changes and change in economic limits.

5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

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.

Proved undeveloped reserves are generally those reserves related to planned infill-drilling locations.

The following table sets out the volumes of proved undeveloped reserves probable undeveloped reserves for the Forecast Price Case, as of December 31, 2016 of the Properties that were first attributed in each of the most recent three financial years and, in the aggregate, before that time, expressed in thousands of barrels ("**Mbbl**") for oil and NGL and millions of cubic feet ("**MMcf**") for sales gas:

	TOTAL COMPANY – FORECAST PRICE CASE							
	Remaining Reserves as of December 31, 2016							
	Light & Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Sales Gas Gross (Mbbl)		NGL Gross (Mbbl)	
Reserves Category	**First Attributed**	**Cumulative at year-end**	**First Attributed**	**Cumulative at year-end**	**First Attributed**	**Cumulative at year-end**	**First Attributed**	**Cumulative at year-end**
Proved Undeveloped								
Prior to December 31, 2014	-	-	-	-	-	-	-	-
December 31, 2014	58	58	-	-	-	-	-	-
December 31, 2015	-	54	-	-	-	-	-	-
December 31, 2016	-	51	-	-	-	-	-	-
Probable Undeveloped								
Prior to December 31, 2014	88	88	-	-	105	105	-	-
December 31, 2014	19	107	-	-	-	106	-	-
December 31, 2015	-	109	-	-	-	109	-	-
December 31, 2016	-	155	-	-	-	104	-	-

Note: The foregoing proved undeveloped reserves form a part of the Fletwode Assets which were not acquired by Petrox until April 2014. The probable undeveloped reserves also include a portion of Petrox's Bashaw Assets.

5.2 Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is 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.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

5.3 Future Development Costs

The following table sets out the costs associated with reserves as set out in the DMCL Report and do not necessarily represent Petrox's full exploration and development budget.

YEAR	Forecast Prices & Costs For Proved Reserves (M$)	For Proved + Probable Reserves (M$)
2017	1,500	1,500
2018	337	337
2019	-	881
2020	-	-
2021	-	-
REMAINING	-	-
TOTAL	1, 837	2,719
Undiscounted	1,837	2,719
Discounted @ 10%	1,723	2,398

Notes:
Notes:
(1) Future Development Costs shown are associated with booked reserves in the DMCL Report and do not necessarily represent Petrox's full exploration and development budget..
(2) The numbers in this table may not add exactly due to rounding.

Petrox proposes to fund the above future development costs through revenues from existing production and from the proceeds through capital financings.

6. OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

Petrox's principal assets are located in the Bashaw area of Alberta (referred to herein as the "**Bashaw Assets**") and in the Fletwode area in Saskatchewan (referred to herein as the "**Fletwode Assets**").

The Fletwode Assets were acquired by Petrox in June 2014 (effective April 2014) and consist of a 100% working interest in a producing light oil property located in the Fletwode area of Saskatchewan. The property is located approximately 90 km Northeast of Estevan, Saskatchewan, and approximately 175 km due West of Brandon, Manitoba. Recent production net to Petrox from its 100% working interest in six producing, low-decline rate Tilston oil wells at Fletwode has averaged approximately 30 barrels of oil per day.

Petrox operates a central battery on the Property, which is located at 06-01-11-04W2. All production is pipelined to the 06-01-11-04W2 battery where oil and water are treated and is separated on site. Produced water is disposed into company operated injection wells and clean oil is stored and trucked Gibson's terminal located in Manitoba.

Petrox acquired the Bashaw Assets in May 2012. The Bashaw Assets are non-producing.

The following table summarizes Petrox's interest as at December 31, 2016 in wells that are producing and non-producing.

	Producing Wells				**Non-Producing Wells**	
	Oil		**Gas**		**Oil/Gas**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	0	0	0	0	0	0
Saskatchewan	6	6	0	0	0	0

6.2 Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which Petrox has an interest effective December 31, 2014. These lands are all located in Alberta, Canada. No work commitments have been made on these lands.

Gross Acres	Net Acres
15,280	15,280

Following are the gross and net acres for which Petrox's rights to explore, develop or exploit will, absent further action, expire within one year.

Gross Acres	Net Acres
4,000	4,000

6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attribute Reserves

Development of the above unproven properties is dependent upon the confirmation of potential oil and gas in place. Petrox is continuing to evaluate potential.

The economic conditions on drilling and completion will determine the timing as to the exploration and development of such properties.

6.3 Forward Contracts

Petrox does not have any product price hedges on forward contracts at December 31, 2016.

6.4 REPEALED

6.5 Tax Horizon

Based on the projected revenue/costs and using forecast prices in the DMCL Report, Petrox estimates that taxes may become payable in the year 2018.

6.6 Costs Incurred

The following table outlines the property acquisition costs, exploration costs and development costs incurred by Petrox during the financial year ended December 31, 2016:

	Property Acquisition Costs	Exploration Costs	Development Costs
Alberta	Nil	Nil	Nil
Saskatchewan	Nil	Nil	Nil

6.7 Exploration and Development Activities

The following table sets out the exploratory and development wells completed by Petrox during the financial year ended December 31, 2016:

	Exploratory Wells				**Development Wells**			
	Oil		**Gas**		**Oil**		**Gas**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	0	0	0	0	0	0	0	0
Saskatchewan	0	0	0	0	0	0	0	0

At present, Petrox does not plan to carry out any exploration and development activities on its properties.

6.8 Production Estimates

The following tables disclose by Reserves Category and by Field, the total volume of production estimated by DMCL for the year 2017 as of December 31, 2016 (Forecast prices and Costs).

	Forecast Prices & Costs		
	Total Proved	**Probable**	**Total Proved + Probable**
RESERVES CATEGORY	**Gross Daily Production [2]**	**Gross Daily Production [2]**	**Gross Daily Production [2]**
Light & Medium Oil (bbls/d)	47	1	48
Heavy Oil (bbls/d)	-	-	-
Associated and Non-Associated Gas (Mcf/d	-	-	-
Natural Gas Liquids (bbls/d)	-	-	-
TOTAL[1] (boe/d)	47	1	48

Notes:
(1) Barrels of Oil Equivalent (BOE) have been reported based on natural gas conversion of 6 Mcf/1 bbl.
(2) Gross production is Company interest before all royalty deductions.

The numbers in this table may not add exactly due to rounding.

FIELD	**Light & Medium Oil (bbl/d)**	**Heavy Oil (bbl/d)**	**Natural Gas[2] (Mcf/d)**	**Natural Gas Liquids (bbl/d)**
Alberta	-	-	-	-
Bashaw	-	-	-	-
Saskatchewan	-	-	-	-
Fletwode	47	-	-	-
TOTAL[1]	47	-	-	-

Notes:
(1) Daily Production is taken from the DMCL Reserves Report as of December 31, 2016.
(2) Natural Gas includes Associated and Non-Associated sales gas volumes.

The numbers in this table may not add exactly due to rounding.

6.9 Production History

The following table sets out for each quarter during the financial year ended December 31, 2016 Petrox's share of average gross daily production volume, the prices received, royalties paid, production costs and the resulting netback.

FIELD	**Light & Medium Oil (/bbl)**				**Heavy Oil (bbl)**				**Natural Gas (Mcf)**				**Natural Gas Liquids (bbl)**			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Alberta - Bashaw																
Production Volume	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Price	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Royalty	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Saskatchewan - Fletwode																
Production Volume	2,795	2,848	2,677	2,857		-	-	-	-	-	-	-	-	-	-	-
Average Price/bbl	$35.43	$49,57	$50.68	$57.58		-	-	-	-	-	-	-	-	-	-	-
Royalty/bbl	$2.13	$2.89	$2.34	$3.12		-	-	-	-	-	-	-	-	-	-	-
Operating Cost/bbl	$31.40	$24.91	$28.30	$25.12		-	-	-	-	-	-	-	-	-	-	-
Netback/bbl	$1.90	$21.77	$20.04	$29.34		-	-	-	-	-	-	-	-	-	-	-

The following table sets out Petrox's production volumes for the financial year ended December 31, 2016

FIELD	**Light & Medium Oil (bbl)**	**Heavy Oil (bbl)**	**Natural Gas (Mcf)**	**Natural Gas Liquids (bbl)**
Alberta	-	-	-	-
Bashaw	-	-	-	-
Saskatchewan	-	-	-	-
Fletwode	11,177	-	-	-
	-	-	-	-
TOTAL	11,177	-	-	-

DEGOLYER AND MACNAUGHTON CANADA LIMITED PRICE FORECAST
EFFECTIVE DATE: December 31, 2016

YEAR	INFLATION %	EXCHANGE RATE USD/CAD	WTI UNESC Constant $US/bbl	WTI @CUSHING $US/bbl	Brent $US/bbl	LIGHT OIL EDMONTON $/bbl	HEAVY OIL 25 API HARDISTY $/bbl	WESTERN CANADIAN SELECT (WCS) 20.5 API $/bbl	HEAVY OIL 12 API HARDISTY $/bbl	CRUDE BITUMEN 9 API HARDISTY $/bbl	NYMEX Henry Hub Reference $US/MMBtu	AECO-C SPOT $/MMBtu	BC WESTCOAST STATION 2 $/MMBtu	EDMONTON ETHANE PRICE $/bbl	EDMONTON PROPANE PRICE $/bbl	EDMONTON BUTANE PRICE $/bbl	EDMONTON PENTANES PLUS $/bbl	PLANT GATE SULPHUR PRICE $/LT
2001	2.4	0.646	-	25.82	24.61	39.48	25.09	-	-	-	4.10	5.53	-	-	30.39	29.53	42.60	10.47
2002	2.4	0.637	-	26.04	24.94	40.11	31.68	-	-	-	3.34	4.08	-	-	20.63	26.59	40.88	9.50
2003	2.5	0.716	-	30.99	28.93	43.52	33.06	-	-	-	5.49	6.67	-	-	31.89	34.60	44.44	40.71
2004	1.7	0.770	-	41.39	38.35	53.06	38.09	-	-	-	6.16	6.56	-	-	34.78	41.21	54.36	39.95
2005	2.0	0.826	-	56.48	55.15	69.28	45.66	43.91	-	-	8.98	8.77	-	-	42.03	50.37	70.75	38.67
2006	1.9	0.882	-	66.02	66.16	73.36	51.90	51.06	-	-	7.01	6.54	6.22	-	44.02	59.44	75.92	19.36
2007	2.1	0.936	-	72.19	72.46	76.87	54.00	53.02	-	-	7.13	6.47	6.40	-	49.58	62.16	78.43	39.46
2008	2.1	0.944	-	99.90	98.64	103.28	84.25	84.34	-	-	9.30	8.17	8.20	-	58.13	77.31	106.01	365.66
2009	1.2	0.880	-	61.68	61.87	66.21	59.94	59.23	-	-	4.16	3.99	4.17	-	37.37	50.76	68.51	4.84
2010	1.7	0.971	-	79.50	80.05	77.63	68.20	67.25	-	-	4.38	4.00	4.01	-	45.76	64.68	84.18	54.34
2011	2.3	1.012	-	95.15	110.88	95.18	77.71	77.08	-	-	4.04	3.64	3.34	-	52.85	77.23	104.45	117.67
2012	1.6	1.000	-	94.20	111.90	85.80	74.56	73.16	-	-	2.82	2.39	2.29	-	37.95	71.98	103.35	128.97
2013	1.2	0.968	-	97.88	108.60	93.48	76.37	75.15	-	-	3.73	3.17	3.11	-	37.23	71.86	104.71	71.72
2014	2.1	0.902	-	92.87	99.38	94.39	81.34	81.57	-	-	4.27	4.48	4.16	-	44.00	63.63	103.93	69.50
2015	1.1	0.784	-	48.87	53.65	57.41	47.02	46.07	-	-	2.63	2.71	1.81	-	6.45	36.83	60.95	80.34
Actual 12 Mo 2016	1.6	0.757	-	41.85	43.53	50.71	37.67	37.43	-	-	2.38	2.17	1.55	-	13.04	34.08	56.15	62.96
Fcst 2017	-	0.760	55.00	55.00	56.20	67.89	55.67	53.95	46.17	45.21	3.50	3.55	3.41	10.18	23.76	45.49	71.29	71.00
2018	2.0	0.780	58.00	59.16	60.36	71.37	60.66	57.54	54.24	48.73	3.30	3.21	3.08	10.71	24.98	49.96	74.94	72.42
2019	2.0	0.800	61.00	63.46	64.66	73.85	62.77	61.12	56.13	52.74	3.40	3.28	3.15	11.08	25.85	51.70	77.54	73.87
2020	2.0	0.825	65.00	68.98	70.18	78.00	66.30	65.60	59.28	57.22	3.60	3.45	3.31	11.70	27.30	54.60	81.91	75.35
2021	2.0	0.850	67.00	72.52	73.75	79.59	67.65	67.49	60.49	59.20	3.80	3.61	3.47	11.94	27.86	55.71	83.57	76.85
2022	2.0	0.850	67.00	73.97	75.22	81.18	69.00	68.84	62.51	60.38	4.00	3.87	3.72	12.18	28.41	56.83	85.24	78.39
2023	2.0	0.850	68.00	76.58	77.85	84.13	71.51	71.54	64.78	62.87	4.08	3.99	3.83	12.62	29.44	58.89	88.33	79.96
2024	2.0	0.850	70.00	80.41	81.71	88.51	75.24	75.68	69.04	66.74	4.16	4.11	3.95	13.28	30.98	61.96	92.94	81.56
2025	2.0	0.850	72.00	84.36	85.68	93.04	79.08	79.95	72.57	70.73	4.24	4.23	4.06	13.96	32.56	65.13	97.69	83.19
2026	2.0	0.850	72.00	86.05	87.40	94.90	80.67	81.55	74.02	72.15	4.33	4.36	4.18	14.24	33.22	66.43	99.65	84.85
2027	2.0	0.850	72.00	87.77	89.15	96.80	82.28	83.18	75.50	73.59	4.42	4.48	4.30	14.52	33.88	67.76	101.64	86.55
2028	2.0	0.850	72.00	89.52	90.93	98.74	83.93	84.84	77.01	75.06	4.50	4.61	4.42	14.81	34.56	69.11	103.67	88.28
2028+	2.0	escalate oil, gas and product prices at 2.0% per year thereafter																

Disclaimer: This price forecast is intended to be used by DMCL's professtionals. Any other persons using this price forecast should have the understanding that it is an estimate of future pricing and should be used at his/her own risk. DMCL and its officers, directors and employees shall not be held responsible or liable for any use of the above information.

APPENDIX “A”

[attached]

DeGolyer and MacNaughton Canada Limited
311 Sixth Avenue S.W., Suite 1430
Intact Place, East Tower
Calgary, Alberta, Canada, T2P 3H2

FORM 51-101F2
REPORT on RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Petrox Resources Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as December 31, 2016, 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 shows the net present value of 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 for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			(M$)	(M$)	(M$)	(M$)
DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	-	3,137	-	3,137

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are 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 our reports referred to in paragraph 4 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated March 6, 2017.

DEGOLYER and MACNAUGHTON
CANADA LIMITED

____
Nahla R. Boury, P.Eng.

PERMIT TO PRACTICE
DeGolyer and MacNaughton Canada Limited

Signature ________________________

Date _________March 6, 2017_________

PERMIT NUMBER: P 5568

The Association of Professional Engineers and Geoscientists of Alberta

APPENDIX “B”

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Petrox Resources Corp. (the “**Corporation**”) is responsible for the preparation and disclosure of information with respect to the Corporation’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, 2016, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation’s reserves data. The report of the independent qualified reserves evaluator is presented above in Appendix “A”.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation’s procedures for providing information to the independent qualified reserves evaluator;

(b) 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

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

The Reserves Committee of the board of directors of the Corporation has reviewed the Corporation’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, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) 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.

(Signed)	*(Signed)*
EDWIN TAM Chief Executive Officer	ALAN CHAN, Chief Financial Officer
(Signed)	*(Signed)*
GARRY LOHUIS Director	HUI YU Director

March 23, 2017