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

Oil and Gas Reserves and Net Present Value of Future Net Revenue

In accordance with National Instrument 51-101 – Standard of Disclosure for Oil and Gas Activities, McDaniel & Associates Consultants Ltd. ("**McDaniel**"), independent petroleum engineering consultants, prepared a report (the "**McDaniel Orca Exploration Report**") dated March 28, 2018. This statement of reserves data and other oil and gas information (this "**Statement**") uses the information provided in the McDaniel Orca Exploration Report. All financial information in this Statement is in US dollars. This Statement was prepared on April 13, 2018 and is effective December 31, 2017.

The McDaniel Orca Exploration Report evaluated, as at December 31, 2017, Orca Exploration Group Inc.'s (the "**Company**" or "**Orca Exploration**") Tanzanian conventional natural gas reserves for the period to the end of its licence in October 2026. The tables below are a summary of the natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Orca Exploration Report utilizing forecast price and cost assumptions. The tables summarize the data contained in the McDaniel Orca Exploration Report and as a result may contain slightly different numbers due to rounding. The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and out of country general and corporate 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 that were assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Orca Exploration Report is based on certain factual data supplied by the Company and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Orca Exploration to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Swala Oil & Gas (Tanzania) plc ("Swala") Investment

On January 16, 2018, Swala (PAEM) Limited ("**Swala PAEM**") acquired 7.93% of the outstanding shares of PAE PanAfrican Energy Corporation ("**PAEM**"), a Mauritius-registered company and the sole shareholder of PanAfrican Energy Tanzania Limited ("**PAET**"). PAET owns and operates Orca Exploration's natural gas exploration, development, and supply business in Tanzania.

The information in this Statement is presented as at December 31, 2017 on the basis of PAET's sole ownership of the Tanzanian reserves as of such date and does not take into account Swala PAEM's current 7.93% ownership of PAET's parent, PAEM.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves

	Company Gross Reserves			Company Net Reserves		
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Convent. Natural Gas**	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Convent. Natural Gas**
	Mbbl	*Mbbl*	*MMcf*	*Mbbl*	*Mbbl*	*MMcf*
Proved						
Developed Producing	-	-	295,951	-	-	183,295
Developed Non-Producing	-	-	10,665	-	-	6,037
Undeveloped	-	-	-	-	-	-
Total Proved	-	-	306,616	-	-	189,332
Probable	-	-	73,448	-	-	54,361
Total Proved plus Probable	-	-	380,064	-	-	243,693

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Future Income Tax Expenses (8) Discounted at					Unit Value Before Tax at 10%
	0%	5%	10%	15%	20%	$/Mcf
(US$'000)						
Proved						
Developed Producing	419,025	327,606	262,626	215,323	180,128	1.43
Developed Non Producing	15,060	10,080	6,864	4,742	3,316	1.14
Undeveloped	-	-	-	-	-	-
Total Proved	434,084	337,686	269,489	220,065	183,444	1.42
Probable	91,368	70,984	56,644	46,302	38,668	1.04
Total Proved plus Probable	525,452	408,670	326,133	266,367	222,112	1.34

	After Future Income Tax Expenses (8) Discounted at				
	0%	5%	10%	15%	20%
(US$'000)					
Proved					
Developed Producing	419,025	327,606	262,626	215,323	180,128
Developed Non Producing	15,060	10,080	6,864	4,742	3,316
Undeveloped	-	-	-	-	-
Total Proved	434,084	337,686	269,489	220,065	183,444
Probable	91,368	70,984	56,644	46,302	38,668
Total Proved plus Probable	525,452	408,670	326,133	266,367	222,112

Notes:

1. The crude oil and natural gas reserves estimates presented in the McDaniel Orca Exploration Report are based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society) as presented in the Canadian Oil and Gas Evaluation (the "**COGE Handbook**"). A summary of those definitions is presented below.
2. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, 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, and shall be disclosed.
3. Reserves are classified according to the degree of certainty associated with the estimates:
   (a) Proved (1P) 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.
   (b) Probable (2P) 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.
   (c) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
   (d) Other criteria that must also be met for the categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.
4. Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:
   (a) 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.
   (b) 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.
   (c) 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.
   (d) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.
5. The qualitative certainty levels referred to in the definitions 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:
   (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
   (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
   (c) at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

   Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5 of the COGE Handbook.
6. "Company Gross Reserves" are the total of the Company's working and/or royalty interest share after Tanzania Petroleum Development Corporation ("**TPDC**") back-in and before deduction of royalties owned by others. It represents the Company's percentage working interest in the property gross reserves.
7. "Company Net Reserves" are the total of the Company's working and/or royalty interest share after deducting the amounts attributable to royalties and Profit Gas owned by others, and represent the Company's share of total Cost Gas and Profit Gas.
8. See "Tax Horizon" for details of tax treatment.
9. There are no state royalties under the Songo Songo Production Sharing Agreement ("**PSA**").
10. In the McDaniel Orca Exploration Report, it is assumed that TPDC will exercise its right to "back-in" to the field development associated with the Songo Songo North well to earn a 20% increase in the profit share for the production emanating from these wells, the "back-in" rights are assumed to be a carried interest. McDaniel has taken the view that this "back-in" right should be treated as a TPDC working interest and therefore the Company Gross Reserves have been adjusted for the volumes of natural gas that are allocated to TPDC for their working interest share. The average effective TPDC working interest in proved plus probable reserves over the life of the licence is 1% or a total of 5,898 MMcf. The outcome of any final agreement on TPDC future back-in rights may lead to a change in the economic terms of the PSA, but cannot be estimated at this time.
11. The separation of the downstream assets was raised by the Ministry Energy and Mines ("**MEM**") in the National Natural Gas Policy issued in 2013, which contemplates TPDC as monopoly aggregator and distributor of gas. In the context of the gas policy, TPDC and MEM have indicated that they wish the Company to unbundle the downstream distribution business in Tanzania. The potential unbundling of the Company's downstream business will be addressed at such time as there is a conflict between new legislation and the Company's right under the PSA. The provisions of the PSA are such that the Company is to be kept economically whole if any legislation affects the Company's economic benefits under the PSA.

12. During the third quarter of 2015, The Petroleum Act, 2015, (the "**Petroleum Act**") was passed into law by Presidential decree. The Petroleum Act repeals earlier legislation; provides a regulatory framework over upstream, midstream and downstream gas activity; and consolidates and puts in place a single comprehensive legal framework for regulating the oil and gas industry in Tanzania. The Petroleum Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory Authority ("**PURA**"). Midstream and downstream petroleum and gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority ("**EWURA**"). The Petroleum Act also confers upon on TPDC the status of the National Oil Company and mandates it with the task of managing Tanzania's commercial interest in petroleum operations as well as midstream and downstream natural gas activities. The Petroleum Act vests TPDC with exclusive rights in the entire petroleum upstream value chain as well as the entire natural gas midstream and downstream value chain. However, the exclusive rights of TPDC do not extend to midstream and downstream petroleum supply operations. The Company is uncertain regarding the potential impact of the Petroleum Act on its business in Tanzania. The Petroleum Act contains grandfathering provisions which uphold the rights of the Company under the PSA, as it was signed prior to the passing of the Petroleum Act. However, it is still unclear how the provisions of the Petroleum Act will be interpreted and implemented regarding upstream and downstream activities.

13. On October 7, 2016, the Government of Tanzania issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258 (I) of the Petroleum Act. Article 260 (3) of the Petroleum Act preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party Natural Gas customers. The impact of the Natural Gas Pricing Regulation, if any, cannot be determined at this time.

Additional Information Concerning Future Net Revenue – (Undiscounted)

(US$'000)	**Revenue[1]**	**Royalties**	**Operat-ing Costs**	**Development Costs**	**Abandon-ment and Reclamatio-n Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Total Proved Reserves	646,542	-	131,983	80,475	-	434,084	-	434,084
Total Proved plus Probable	845,808	-	137,156	183,200	-	525,452	-	525,452

Note:

1. Revenue is net of Additional Profits Tax which is a form of royalty.

Future Net Revenue by Production Group

(US$'000)	**Future Net Revenue Before Future Income Tax Expenses Discounted at 10%**	**Net Unit Value Before Income Taxes Discounted at 10% ($/Mcf)**
Proved		
Light and Medium Crude Oil [(1)]	-	-
Natural Gas Liquids	-	-
Conventional Natural Gas [(2)]	269,489	1.42
Proved plus Probable		
Light and Medium Crude Oil [(1)]	-	-
Natural Gas Liquids	-	-
Conventional Natural Gas[(2)]	326,133	1.34

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.

Pricing Assumptions – Forecast Prices, Costs and Gas Sales

McDaniel employed the following gas sales, pricing and inflation rate assumptions as of December 31, 2017 in estimating the Company's reserves data using forecast prices and costs. The Company received an average gas price of US$4.84/Mcf in 2017.

		Songo Songo gas prices		
	Brent crude	Proved	Proved plus probable	Annual inflation %
Year	US$/bbl	US$/Mcf	US$/Mcf	
2018	63.50	4.05	3.94	2
2019	61.30	3.94	4.00	2
2020	63.40	3.95	4.01	2
2021	70.10	4.12	4.07	2
2022	74.20	4.27	4.22	2
2023	75.60	4.39	4.35	2
2024	77.10	4.35	4.36	2
2025	78.60	4.29	4.33	2
2026	80.30	4.37	4.41	2

The Company sells its natural gas to Industrial customers under various industrial contracts ("**Industrial Contracts**"). The Industrial Contracts have caps and floors with regards to gas prices. The industrial gas prices are determined by approved discounts to Heavy Fuel Oil unless this price is above the cap or below the floor price stipulated in the contract. The price of gas for the Industrial sector is based on a formula related to heavy fuel oil prices and includes caps and floors. This has been reflected in the above pricing.

The price of natural gas sold to Wazo Hill is based on the contracted prices as set out in the Amendment Agreement No2 dated October 2017 to the 2008 gas sales agreement with Tanzania Portland Cement Company plus an estimation of the Songas transportation tariff as determined by the energy regulator, EWURA.

The price of natural gas for the Power sector is set by reference to a base price of $1.87/MMBTU in 2008 escalated at 2% per annum plus an estimation of the Songas transportation tariff as determined by EWURA. The base price of the gas to the Power sector increased to US$2.50/MMBTU on July 1, 2012 which is the equivalent of US$2.76/MMBTU after the annual 2% escalation pursuant to the terms of the long term power agreements with TANESCO and Songas.

The National Natural Gas Infrastructure Project Gas Processing Plant on Songo Songo Island was commissioned in 2016 ("**NNGIP Gas Processing Plant**" and together with its infrastructure, including a pipeline to Dar-es-Salam, the "**NNGIP Infrastructure**"). The Songas Gas Processing Plant on Songo Songo Island was commissioned in 2004 ("**Songas Gas Processing Plant**" and together with its infrastructure, including the main pipeline to Dar-es-Salam, the "**Songas Infrastructure**"). Gas sales to TANESCO can be made via both the NNGIP Infrastructure and Songas Infrastructures. In order to facilitate sales via the NNGIP Infrastructure the Company will be connecting the SS-10, SS-11 and SS-12 wells to the NNGIP Infrastructure. Any new TANESCO delivery points will be supplied via the NNGIP Infrastructure, subject to well deliverability constraints. Sales to TANESCO will be priced according to the Portfolio Gas Supply Agreement between TPDC, the Company's subsidiary, and TANESCO (the "**PGSA**") well head price, which was US$2.76 MMBTU on 1 July 2012 (escalating 2% per annum). The Company has been in discussions with TPDC regarding a new gas sales agreement. It has been assumed that under that new gas sales agreement, volumes will be priced at US$3.00 Mcf on January 1, 2017 (escalating 2% per annum) exclusive of any processing and transportation tariff. Sales made via the Songas Infrastructure will be at the TANESCO plant gate, while sales made via the NNGIP Infrastructure are made at the wellhead. There is no guarantee that this proposed price will be realized and as such there could be further adjustments to the Company's 2P present value once the negotiations are finalized and a new gas sales agreement is signed with TPDC. These new price assumptions for TPDC have resulted in a decline in Songo Songo gas prices from the 2016 reserve report.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of the Company's total gross working interest proved and proved plus probable conventional natural gas reserves as at December 31, 2017 against such reserves as at December 31, 2016.

	Gross Associated and Non-Associated Conventional Natural Gas (Bcf)		
	Proved	**Probable**	**Proved plus Probable**
Reserves at December 31, 2016	**347.4**	**57.9**	**405.3**
Extensions	-	-	-
Improved recovery	-	-	-
Technical revisions [1]	(25.6)	15.5	(10.1)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic factors	-	-	-
Production	(15.2)	-	(15.2)
Reserves at December 31, 2017	**306.6**	**73.4**	**380.1**

Note:
1. The proved technical revisions because the gas sales forecast prior to license expiry is expected to be lower.

On a Company Gross basis there has been a 12% decline in Songo Songo's 1P Additional Gas reserves to the end of the license period from 347.4 Bcf to 306.6 Bcf with total Additional Gas production of 15.2 Bcf during the year. There has been a 6% decline in the 2P Additional Gas reserves on a Company Gross life of license basis from 405.3 Bcf to 380.1 Bcf.

UNDEVELOPED RESERVES

The following table sets forth the undeveloped reserves for the years prior to December 31, 2015 and years ended December 31, 2015, 2016, and 2017.

	As of December 31, 2017 Conventional Natural Gas	
Proved Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
2015	-	121,896
2016	-	-
2017	-	-

Probable Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
2015	-	36,484
2016	-	22,922
2017	-	32,447

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

Proved Undeveloped Reserves

All of the Company's proved undeveloped reserves were developed in 2016 due to the completion of the Offshore Development Program in that year.

Probable Undeveloped Reserves

Probable undeveloped reserves were assigned for the development of areas of the Songo Songo North pool that are further away from well control than assigned in the proved reserves case.

The Company intends to develop the undeveloped reserves by the drilling of new wells as and when required to meet the demand for gas by consumers.

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. The Company's reserves are evaluated by McDaniel, an independent petroleum engineering firm.

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

Although every reasonable effort is made to ensure that reserve estimates are accurate, 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.

In the McDaniel Orca Exploration Report, it is assumed that TPDC will exercise its right to "back-in" to the field development associated with the SS-N well to earn a 20% increase in the profit share for the production emanating from this well, the "back-in" rights are assumed to be a carried interest. McDaniel has taken the view that this "back-in" right should be treated as a TPDC working interest and therefore the Gross Property reserves have been adjusted for the volumes of natural gas that are allocated to TPDC for their working interest share. The outcome of any final agreement on TPDC future "back-in" rights may lead to a change in the economic terms of the PSA, but cannot be estimated at this time.

The separation of the downstream assets was raised by MEM in the National Natural Gas Policy issued in 2013, which contemplates TPDC as monopoly aggregator and distributor of gas. In the context of the gas policy, TPDC and MEM have indicated that they wish the Company to unbundle the downstream distribution business from its upstream business in Tanzania. The potential unbundling of the downstream business will be addressed at such time as there is a conflict between new legislation and the Company's right under the PSA. The provisions of the PSA are such that the Company is to be kept economically whole if any legislation affects the Company's economic benefits under the PSA.

During the third quarter of 2015, the Petroleum Act was passed into law by Presidential decree. The Petroleum Act repeals earlier legislation' provides a regulatory framework over upstream, midstream and downstream gas activity' and consolidates and puts in place a single comprehensive legal framework for regulating the oil and gas industry in Tanzania. The Petroleum Act also provides for the creation of an upstream regulator, PURA. Midstream and downstream petroleum and gas activities are proposed to be regulated by the current authority, EWURA. The Petroleum Act also confers upon on TPDC the status of the National Oil Company and mandates it with the task of managing Tanzania's commercial interest in petroleum operations as well as midstream and downstream natural gas activities. The Petroleum Act vests TPDC with exclusive rights in the entire petroleum upstream value chain and the entire natural gas midstream and downstream value chain. However, the exclusive rights of TPDC do not extend to midstream and downstream petroleum supply operations. The Company believes the potential impact of the Petroleum Act on its business in Tanzania will not be significant as the PSA was signed prior to passing of the Petroleum Act and there are grandfathering provisions within the Petroleum Act upholding the rights of the Company under the PSA.

On October 7, 2016, the Government of Tanzania issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258 (I) of the Petroleum Act. Article 260 (3) of the Petroleum Act preserves the Company's pre-existing right under the PSA with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party Natural Gas customers. The impact of the Natural Gas Pricing Regulation, if any, cannot be determined at this time.

FUTURE DEVELOPMENT COSTS

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved and probable reserves using forecast prices and costs.

	Future Development Costs Forecast Prices and Costs	
	Proved	**Proved plus Probable**
(US$'000)		
2018	20,040	20,040
2019	18,284	18,692
2020	16,750	28,611
2021	849	15,175
2022	11,366	53,905
Remaining Years	13,186	46,777
Total Undiscounted	80,475	183,200

The 2018 future development costs include: i) the installation of field refrigeration at the Songas Gas Processing Plant and ii) the tie-in of the SS-12 well to the NNGIP Infrastructure.

The 2018 to 2019 future development costs include: i) the work-over of the SS-3 and SS-4 wells (currently suspended and shut-in respectively) and ii) the recompletion of the SS-10 well with chrome production tubing.

The 2019 to 2020 future development costs include Phase II of the Songo Songo development program which includes the installation of compression downstream of the Songas Gas Processing Plant**.**

Phase III of the development program includes the drilling and completion of one Songo Songo North well which will start incurring capital expenditures in 2020 up to 2022.

The Company has many financing alternatives available to fund its capital program, including future development costs, including partial retention of funds from operations, bank debt financing, issuance of additional equity, and issuance of convertible debentures and other financial instruments. The Company evaluates the appropriate financing alternatives closely and may make use of all these options dependent on the given investment situation and the capital markets. The Company maintains a capital structure that is intended to maximize the investment return to its shareholders as compared to the cost of financing. The Company expects to continue using all financing alternatives available to continue pursuing its development strategy. The assorted financing instruments have certain inherent costs which are considered in the economic evaluation of pursuing any development opportunity.

There can be no guarantee that funds will be available or that the Company will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of any of its assets uneconomic.

Land Holdings

The following table set out the developed and undeveloped land holdings in acres of the Company as at December 31, 2017.

	Developed		Undeveloped		Total	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Songo Songo	53,623		-	-	53,623	
Total Tanzania	53,623		-	-	53,623	

Notes:

1. "Gross" refers to the total acres of the property in which Orca Exploration or its subsidiaries have an interest.
2. "Net" refers to the total acres in which Orca Exploration or its subsidiaries have an interest, multiplied by the effective working interest percentage owned therein after taking into account the expected TPDC "back-in" rights.

OIL AND GAS PROPERTIES AND WELLS

The following table summarizes the Company's interest as at December 31, 2017 in wells that are producing and non-producing.

	Producing Wells		Non-Producing Wells	
	Natural Gas		Natural Gas	
	Gross	Net	Gross	Net
Songo Songo	**6.0**	**6.0**	**2.0**	**2.0**
Total Tanzania	**6.0**	**6.0**	**2.0**	**2.0**

Producing Wells.

As at December 31, 2017, the Company had an interest in five producing wells, three offshore wells (SS-5, SS-7, and SS-9) and two onshore wells (SS-10 and SS-11). The SS-10 well was drilled in 2007 and tied-in to the Songas Gas Processing Plant in January 2011. The SS-11 well was completed in June 2012 and was tied-in to the Songas Gas Processing Plant in September 2012. The SS-9, SS-5 and SS-7 wells were worked over as part of the Phase I development program in September through November 2015 and where put back into production in October through December 2015. The SS-11 well is tied into the Songas Gas Processing Plant via the SS-5 offshore flowline and is also tied into the NNGIP Infrastructure.

Non-Producing Wells

As at December 31, 2017, the Company had an interest in three non-producing wells, two onshore wells (SS-3 and SS-4) and one offshore well (SS-12). The offshore well, SS-12, was successfully completed in February 2016 and encountered the top reservoir approximately 100 meters higher than expected. SS-12 is currently shut in and is expected to be tied into the NNGIP Infrastructure in 2018. SS-3 was suspended in 2011 and SS-4 was shut in December 2015 following the completion of offshore work-overs. The two onshore wells are planned to be the subject of a work-over program in 2018 as described in *Future Development Costs* above.

After the completion of the refrigeration the Company can produce approximately 155 MMscfd from the five wells, SS-5, SS-7, SS-9, SS-10 and S-11. The SS-12 well adding a further 35 MMcfd. However, prior to the completion of the Gas Sale Agreement with TPDC, production is limited to the Songas Infrastructure. The current Songas Infrastructure has a maximum capacity of 102 MMscfd, with the NNGIP Infrastructure having an additional infrastructure capacity of 140 MMscfd.

Infrastructure

The Songas Gas Processing Plant is owned by Songas and is operated by Orca Exploration on behalf of Songas (on a no loss/no profit basis). The Songas Gas Processing Plant consists of 2 x 35 MMscfd raw gas trains.

In June 2011, the Company installed joule thomson valves at the Songas Gas Processing Plant and subsequently signed a Re-Rating Agreement with Songas and TANESCO to increase the gas processing capacity from 90 MMscfd to 110 MMscfd (the plant was re-rated and certified at these rate). This increased the overall capacity of the Songas Gas Processing Plant to 102 MMcfd with the pipeline diameter being the bottleneck. The Re-Rating Agreement expired on December 31, 2012 and, although it was initially extended to December 31, 2013, no new agreement is currently in place. Without the Re-Rating Agreement, the Songas Gas Processing Plant could be de-rated to 70 MMcfd (the capacity originally agreed to) if there were any technical or safety reasons to do so. However the Songas Gas Processing Plant is inspected each year and to date has continuously been certified to produce at 110 MMscfd. If the Songas Gas Processing Plant was de-rated it would result in a material reduction in the Company's sales volumes of Additional Gas.

The Company's gas is transported the Songas Gas Processing Plant to Dar-es-Salaam via a 25Km 12-inch offshore pipeline to Somanga Funga landfall then via a 207 km 16-inch onshore pipeline to Ubungo Power Plant and a 16 km 8-inch lateral pipeline to the Wazo Hill cement plant. These pipelines are operated and owned by Songas.

Sales of Additional Gas to Industrial customers are made via the Company's low pressure distribution system. There are three pressure reduction stations and two separate connections to the 16-inch high pressure pipeline. Since 2004, the Company has constructed over 50 km of low pressure pipeline in Dar es Salaam and 40 Industrial customers were connected and consuming Additional Gas at the end of 2017.

The NNGIP Infrastructure at Songo Songo Island was commissioned in 2016. The NNGIP Gas Processing Plant includes 2 x 70 MMscfd raw gas trains. Gas is transported via a 16-inch offshore pipeline (twinned with the Songas Infrastructure) to Somanga Funga landfall then via a 207 km 36-inch offshore pipeline to Dar-es-Salaam. These pipelines are owned and operated by TPDC.

PROPERTIES WITH NO ATTRIBUTED RESERVES

Tanzania

The Company does not have any interests in unproved properties in Tanzania and there are no properties in which the Company's rights to explore, develop or exploit will, absent further action, expire within one year in Tanzania.

Italy

Elsa

On 30 May 2010, the Company signed an agreement to farm-in to the Central Adriatic B.R268.RG Permit offshore Italy (the "**Italy Permit**"). The farm-in commits the Company to fund 30% of the Elsa-2 appraisal well up to a maximum of US$11.5 million to earn a 15% working interest in the Italy Permit. Thereafter, the Company will fund all future costs relating to the well and the Italy Permit in proportion to its participating interest. The Company has also agreed to pay the owner fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million. Changes in Italian environmental legislation in late 2015 resulted in the development of the Italy Permit being postponed indefinitely. As at the date of this report, the Company has no further capital commitments in Italy.

EXPLORATION AND DEVELOPMENT ACTIVITY

The Company did not conduct any drilling activities for the year ended December 31, 2017.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

There are no estimates of well abandonment costs included in the McDaniel Orca Exploration Report in arriving at future net revenue.

Under the terms of the PSA, Orca Exploration is not currently liable for abandonment and reclamation costs as it is envisaged that the wells will continue to produce after Orca Exploration has relinquished the licence. The Tanzanian Government has stated a desire for the Company to contribute towards an escrow account for future abandonment costs based on a per unit of production basis. The Company will provide for abandonment costs once an agreement is reached with TPDC and the PSA amended accordingly.

TAX HORIZON

Under the terms of the Production Sharing Agreement ("PSA"), the Company is required to pay Tanzanian income tax, but this is recovered by the Company through the profit sharing arrangements with TPDC. Where income tax is accrued, the Company's revenue will be grossed up by the tax due and the tax will be shown as a tax in the Company's accounts. However, the income tax has no material impact on the cash flows emanating from the PSA and accordingly it has not been identified as a separate cash flow stream in the analysis of net present values.

The Company does not pay any royalties. However, under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("**PPI**"), an Additional Profits Tax ("**APT**") is payable at a rate of 25% of the Company's profit share. This rate can increase to 55% of the Company's profit share where all costs have been recovered with an annual return of 35% plus the PPI.

The APT can have a significant impact on project economics as measured by the net present value of the cash streams emanating under the PSA. Higher revenue in the initial years leads to a rapid payback of the project costs and consequently accelerates APT payments. Therefore, the terms of the PSA rewards the Company for taking higher risks by incurring capital expenditure in advance of revenue generation.

The APT has been netted off against revenue rather than identified as a separate cash flow stream in the analysis of net present values under both constant and forecast price cases, as its payment and calculation is determined by the terms of the PSA and is applicable only to reserves within the Songo Songo PSA rather than as income tax expense as are most corporate income taxes.

COSTS INCURRED

The following table summarizes the Company's property acquisition costs, exploration costs and development costs for the year ended December 31, 2017.

	Year ended 31 December 2017
(US$'000)	
Lease acquisition and retention	-
Geological and geophysical	-
Drilling and completion	30
Production equipment	-
Infrastructure	1,262
Capitalized general and administrative	-
Development	-
Decommissioning asset	-
Total	**1,292**
Cost by category	
Acquisition of proved properties	-
Acquisition of unproved properties	-
Exploration costs	-
Development costs	1,292
Other costs	-
Total	**1,292**

Further analysis of capital expenditures

The tables below summarize the Company's quarterly capital expenditures for the year ended December 31, 2016.

	Quarter ended			
(US$'000)	**31 December 2017**	**30 September 2017**	**30 June 2017**	**31 March 2017**
Property acquisitions and retention	-	-	-	-
Geological and geophysical including drilling and completion and production equipment	-	-	3	27
Development and facilities	442	477	250	93
Power development	-	-	-	-
	442	477	253	120

Personnel

As at December 31, 2017, the Company had a full time complement of 55 full-time personnel, excluding approximately two consultants and contract personnel who devoted the majority of their time to the Company. In addition the Company employs 36 employees who are recharged to Songas for the operation of the Songas Gas Processing Plant.

Location	**Number of full time personnel**
Tanzania – Head office	55
Tanzania – Songo Songo Island (Operatorship)	36
London – Service office	3
	94

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by McDaniel for the year ending December 31, 2018 in the estimates of future net revenue from proved and proved plus probable reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue of Oil and Gas Reserves".

2018 Forecast Production

(MMcfpd)	Proved	Proven plus Probable
Songo Songo natural gas	61,929	73,132
Total	61,929	73,132

PRODUCTION HISTORY

The following tables disclose the Company's quarterly average gross daily production of conventional natural gas and the Company's net production (after TPDC profit share) for the year ended December 31, 2017.

Average Daily Production

	Quarter Ended			
Production Songo Songo	**31-Dec-17**	**30-Sep-17**	**30-Jun-17**	**31-Mar-17**
Gross Company (MMcfd)	38.5	45.1	39.5	43.5
Net Company (MMcfd)	20.3	32.2	33.08	36.9
Prices US$/Mcf				
Industrials	7.52	7.65	7.69	7.75
Power	3.63	3.63	3.57	3.57
Average prices received	4.93	4.87	4.90	4.68
Tariff	(0.59)	(0.59)	(0.59)	(0.59)
TPDC share of revenue	(1.81)	(1.10)	(0.63)	(0.54)
Production costs US$/Mcf	(0.27)	(0.24)	(0.24)	(0.21)
Resulting netback US$/Mcf	2.26	2.94	3.44	3.34

Production Volume by Field

The following table discloses for each important field, and in total, the Company's gross production volumes for the year ended December 31, 2017 for each product type.

(MMcf)	**Conventional Natural Gas**
Songo Songo gas field	15,199