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 14, 2017. 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 12, 2017 and is effective December 31 2016.

The McDaniel Orca Exploration Report evaluated, as at December 31, 2016, Orca Exploration Group Inc.’s (the “Company” or “Orca Exploration”) Tanzanian 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 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.

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	-	-	343,564	-	-	209,611
Developed Non-Producing	-	-	3,821	-	-	2,178
Undeveloped	-	-	-	-	-	-
Total Proved	-	-	347,385	-	-	211,789
Probable	-	-	57,935	-	-	47,358
Total Proved plus Probable	-	-	405,320	-	-	259,147

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	540,684	404,628	312,053	247,337	200,953	1.49
Developed Non Producing	3,989	2,171	1,011	61	(229)	0.46
Undeveloped	-	-	-	-	-	-
Total Proved	544,673	406,799	313,065	247,598	200,724	1.48
Probable	84,169	63,680	49,853	40,268	33,454	1.05
Total Proved plus Probable	628,841	470,479	362,918	287,865	234,177	1.40

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	0%	5%	10%	15%	20%
(US$'000)					
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Developed Non Producing	3,989	2,171	1,011	61	(229)
Undeveloped	-	-	-	-	-
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Notes:

1. The crude oil and natural gas reserves estimates presented in the McDaniel Orca Exploration Report have been 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 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 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 in the Songo Songo Production Sharing Agreement ("PSA").
10. In the McDaniel Orca Exploration Report, it has been 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 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 Gross Property 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 3,525 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 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 "Act") was passed into law by Presidential decree. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and as well consolidates and puts in place a single, effective and comprehensive legal framework for regulating the oil and gas

industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory. The mid and downstream petroleum as well as gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority. The Act also confers upon on TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in the petroleum operations as well as mid and downstream natural gas activities. The Act vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC does not extend to mid and downstream petroleum supply operations. The Company is uncertain regarding the potential impact on its business in Tanzania. The Act does provide grandfathering provisions upholding the rights of the Company under the PSA as it was signed prior to the passing of the Act. However , it is still unclear how the provisions of the 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 Act. Under the Act, Article 260 (3) 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	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Total Proved Reserves	776,493	-	147,795	84,026	-	544,673	-	544,673
Total Proved plus Probable	976,244	-	152,451	152,451	-	628,841	-	628,841

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]	-	-
Conventional Natural Gas[2]	313,065	1.48
Proved plus Probable		
Light and Medium Crude Oil[1]	-	-
Conventional Natural Gas[2]	362,918	1.40

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, 2016 in estimating the Company's reserves data using forecast prices and costs. The Company received an average gas price of US$4.73/Mcf in 2016.

		Songo Songo gas prices		
	Brent crude	Proved	Proved plus probable	Annual inflation %
Year	US$/bbl	US$/Mcf	US$/Mcf	
2017	56.00	4.33	4.38	2
2018	59.70	4.21	4.19	2
2019	63.40	4.21	4.29	2
2020	70.10	4.29	4.35	2
2021	76.90	4.41	4.44	2
2022	78.40	4.50	4.55	2
2023	79.90	4.60	4.70	2
2024	81.50	4.65	4.76	2
2025	83.20	4.67	4.78	2
2026	84.90	4.77	4.88	2

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 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 the energy regulator, Energy and Water Utility Regulatory Authority. The base price of the gas to the power sector increased to US$2.50/MMBTU on July 1, 2012 the equivalent of US$2.76/MMBTU after the annual 2% escalation pursuant to the terms of the long term power agreements.

The National Natural Gas Infrastructure Project ("NNGIP") Gas Processing Plant on Songo Songo Island was commissioned in 2016. Gas sales to TANESCO will be made via both the NNGIP and Songas Infrastructures. In order to facilitate sales via the NNGIP 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. The Company has been in discussions with TPDC with regards to a new Gas Sales Agreement. It has been assumed that volumes up to 37 MMBTU supplied to TANESCO power plants (via either infrastructure) will be priced according to the Portfolio Gas Supply Agreement ("PGSA") well head price, US$2.76 MMBTU on July 1, 2012 (escalating 2% per annum), with volumes in excess of 37 MMBTU priced at US$3.50 MMBTU 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 with sales made via the NNGIP infrastructure being 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 finalised and a new gas sales agreement is signed with TPDC.

The price of natural gas sold to Wazo Hill is based on the contracted prices as set out in the First Amendment Agreement (dated May 2014) 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, Energy and Water Utility Regulatory Authority.

The slight increase in the gas price from 2017 is a result of the lower Brent crude price forecast being below the floor price stipulated in many of the industrial customer 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.

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 reserves as at December 31, 2016 against such reserves as at December 31, 2015.

	Gross Associated and Non-Associated Conventional Natural Gas (Bcf)		
	Proved	**Probable**	**Proved plus Probable**
Reserves at December 31, 2015	**367.8**	**49.1**	**416.9**
Extensions	-	-	-
Improved recovery	-	-	-
Technical revisions[(1)]	(3.5)	8.8	5.3
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic factors	-	-	-
Production	(16.9)	-	(16.9)
Reserves at December 31, 2016	**347.4**	**57.9**	**405.3**

1. The proved technical revisions were as a result of drilling well SS-12 and because the gas sales forecast prior to license expiry is expected to be lower.

On a Gross Company basis there has been a 6% decline in Songo Songo's 1P Additional Gas reserves to the end of the license period with total Additional Gas production of 16.9 Bcf during the year. There has been a 3% decline in the 2P Additional Gas reserves on a Gross Company life of license basis from 416.9 Bcf to 405.3 Bcf. The decrease is a consequence of 2016 Additional Gas Production of 16.3 Bcf offsetting the higher anticipated growth in power demand in the latter half of the license period.

UNDEVELOPED RESERVES

The following table sets forth the undeveloped reserves for the years ended December 31, 2014, 2015, and 2016.

	As of December 31, 2016 Conventional Natural Gas	
Proved Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
Prior to 2014	170,750	170,750
2014	-	166,756
2015	-	121,896
2016	-	-

Probable Undeveloped	1st Attributed (MMcf)	Booked (MMcf)
Prior to 2014	36,132	36,132
2014	-	60,173
2015	-	36,484
2016	-	22,922

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

Proved undeveloped reserves have developed in the period due to completion of the Offshore Development Program in 2016.

Probable Undeveloped Reserves

Probable undeveloped reserves were assigned for the development of areas of the pool that are further away from well control than assigned in the proved reserves case. The decrease in 2016 is for same reason the proved undeveloped reserves have decreased.

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 has been 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 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 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 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 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, 2015, (the "Act") was passed into law by Presidential decree. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and as well consolidates and puts in place a single, effective and comprehensive legal framework for regulating the oil and gas industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory. The mid and downstream petroleum as well as gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority. The Act also confers upon on TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in the petroleum operations as well as mid and downstream natural gas activities. The Act vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC does not extend to mid and downstream petroleum supply operations. The Company believes the potential impact on its business in Tanzania will not be significant as the PSA was signed prior to passing of the Act and there are grandfathering provisions within the 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 Act. Under the Act, Article 260 (3) 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.

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)		
2017	2,500	2,500
2018	27,142	35,924
2019	20,964	40,992
2020	19,314	67,493
2021	11,366	11,799
Remaining Years	2,740	36,244
Total Undiscounted	84,026	194,952

The 2017 future development costs in 2017 includes: i) instrumentation work for the tie in of the SS-10 and SS-11 wells into the NNGIP infrastructure, ii) upgrade of the SS-12 well platform and iii) capital costs associated with the connection of new industrial customers.

The 2018 future development costs include: i) the installation of field refrigeration at the Songas gas processing facility, ii) tie-in the SS-12 well to the NNGIP infrastructure and iii) the work-over of the SS-3 and SS-4 wells (currently suspended and shut-in respectively) and the recompletion of the SS-10 well with chrome production tubing. There is the possibility that the installation of field refrigeration may be accelerated to the last quarter of 2017.

Phase II of the proved plus probable capital expenditure from 2017 onwards includes the installation of compression downstream of the Songas facility.

Phase III of the development programme including the undertaking of a 3D seismic programme over Songo Songo North and Songo Songo West and the drilling and completion of one Songo Songo North well.

The Company does not expect to commit to future development costs beyond 2017 until: i) agreeing commercial terms with TPDC for the supply of gas to the NNGIP regarding the sale of incremental gas volumes from Songo Songo, ii) TANESCO arrears have been substantially reduced, guaranteed or other arrangements for payment made which are satisfactory to the Company and iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any new sales contracts with Government entities.

When the above conditions above are met, and as a result there is justification for further improving the reliability/capacity of field deliverability, the Company will contemplate undertaking the balance of the Phase I Development Program. The additional costs are estimated to be approximately US$30.1 million.

Land Holdings

The following table set out the developed and undeveloped land holdings of the Company as at December 31, 2016:

	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, 2016 in wells that are producing and non-producing.

	Producing Wells		Non-Producing Wells	
	Natural Gas		Natural Gas	
	Gross	Net	Gross	Net
Songo Songo	**5.0**	**5.0**	**3.0**	**3.0**
Total Tanzania	**5.0**	**5.0**	**3.0**	**3.0**

Producing Wells

At the year end 2016 there were 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 drilled in 2007 was tied in to the gas processing plant in January 2011. The SS-11 well was completed in June 2012 and was tied in to the 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/October and November 2015 respectively and were put back into production in October/November and December 2015 respectively. The SS-11 well is currently tied into the Songas Gas Processing Plant via the SS-5 offshore flowline.

Non-Producing Wells

At year end 2016 there were three non-producing wells, SS-3 and SS-4 (located onshore) and SS-12 (located offshore). The offshore well SS-12 was successfully completed in February 2016, encountering the top reservoir approximately 100 meters high to prognosis. The well is currently shut in and is expected to be tied into the NNGIP infrastructure in 2017/2018. The onshore well SS-3 was suspended in 2011 and the SS-4 well was shut in December 2015 following the completion of the offshore work-overs. The two onshore wells are planned to be the subject of a work-over programme in 2018 as described above.

Currently, the Company can produce approximately 155 MMcfd from the five wells, SS-5, SS-7, SS-9, SS-10 and S-11 (SS-12 well adding a further 35 MMcfd). The current Songas infrastructure has a maximum capacity of 102 MMcfd, with the NNGIP having an additional infrastructure capacity of 140 MMcfd.

Infrastructure

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

In June 2011, the Company installed joule thomson valves at the Gas Processing Plant and subsequently signed a Re-rating Agreement with Songas and TANESCO to increase the gas processing capacity from 90 MMcfd to 110 MMcfd (the plant was re-rated and certified at these rate). This increased the overall capacity of the system 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 Gas Processing Plant could be be de-rated to 70 MMcfd (the capacity originally agreed to) if there were any technical or safety reasons to do so however the plant is inspected each year and certified to produce at 110 MMcfd. If the plant was de-rated on the ground of technical or safety reasons this would result in a material reduction in the Company's sales volumes of Additional Gas.

The gas is transported to Dar-es-Salaam via a 25 km 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 the 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 38 industrial customers were connected and consuming Additional Gas at the end of 2016.

The NNGIP infrastructure at Songo Songo Island was commissioned in 2016. The NNGIP Gas Processing Plant includes 2 x 70 MMcfd 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 following table summarizes the gross and net acres of unproved properties in which the Company has an interest and also the number of net acres for which the Company's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year	Nature, cost and timing of work commitments US$'000
Songo Songo	-	-	-	-
Total Tanzania	-	-	-	-

Italy

Elsa

On May 30, 2010, the Company signed an agreement to farm-in to the Central Adriatic B.R268.RG Permit offshore Italy. 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 permit. Thereafter, the Company will fund all future costs relating to the well and the 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, have resulted in the development of this 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 following table summarizes the Company's drilling results for the year ended December 31, 2016

	2016	
Italy	**Gross**	**Net**
Exploration		
Natural Gas	-	-
Suspended	-	-
Dry and Abandoned	-	-
Total Exploration	-	-
Songo Songo - Tanzania		
Development		
Natural Gas	1	1
Suspended	-	-
Dry and Abandoned	-	-
Total Development	1	1
Total	-	-

Tanzania

The SS-12 development well was spud in December 2015 and was completed in February 2016. The SS-12 well is a vertical offshore well drilled to a total measured depth of 2,130 metres.

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. While there is currently no amendment to the PSA, the 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 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 the 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 the 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 the payment of the APT. 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 the net present values under both the 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 Tanzanian property acquisition costs, exploration costs and development costs for the year ended December 31, 2016.

	Year ended December 31, 2016
(US$'000)	
Lease acquisition and retention	-
Geological and geophysical	-
Drilling and completion	16,255
Production equipment	-
Infrastructure	565
Capitalized general and administrative	-
Development	-
Decommissioning asset	-
Total	**16,820**
Cost by category	
Acquisition of proved properties	-
Acquisition of unproved properties	-
Exploration costs	-
Development costs	16,820
Other costs	-
Total	**16,820**

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)	**December 31, 2016**	**September 30, 2016**	**June 30, 2016**	**March 30, 2016**
Property acquisitions and retention	-	-	-	-
Geological and geophysical including drilling and completion and production equipment	32	26	2,558	13,639
Development and facilities	99	(71)	181	356
Power development	-	-	-	-
	131	(45)	2,739	13,995

Personnel

As at December 31, 2016, the Company had a full time complement of 57 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 37 employees who are recharged to Songas for the operatorship of the gas processing plant.

Location	**Number of full time personnel**
Tanzania – Head office	57
Tanzania – Songo Songo Island (Operatorship)	37
London – Service office	4
	97

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by McDaniel for 2017 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".

2017 Forecast Production

(MMcf)	**Proved**	**Proven plus Probable**
Songo Songo natural gas	17,129	18,360

PRODUCTION HISTORY

The following tables disclose the Company's quarterly average gross daily production and the Company's net production (after TPDC profit share) for the year ended December 31, 2016.

Average Daily Production

	Quarter Ended			
Production Songo Songo	**December 31, 2016**	**September 30, 2016**	**June 30, 2016**	**March 31, 2016**
Gross Company (MMcfd)	44.8	46.6	40.4	46.3
Net Company (MMcfd)	38.07	39.6	34.3	39.4
Prices US$/Mcf				
Industrials	7.52	7.60	7.64	8.15
Power	3.57	3.57	3.55	3.55
Average prices received	4.75	4.73	4.83	4.61
Tariff	(0.59)	(0.59)	(0.61)	(0.68)
TPDC Profit Gas	(0.56)	(0.62)	(0.63)	(0.59)
Production costs US$/Mcf	(0.25)	(0.21)	(0.27)	(0.26)
Resulting netback US$/Mcf	3.34	3.31	3.32	3.08

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, 2016 for each product type.

(MMcf)	**Natural Gas**
Songo Songo gas field	16,931