Management's Discussion & Analysis

ORCA EXPLORATION GROUP INC.

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THIS MD&A OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30 2014 SHOULD BE READ IN CONJUNCTION WITH THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS AS AT AND FOR THE THREE AND NINE MONTH PERIODS ENDED 30 SEPTEMBER 2014 AND NOTES THERETO AND THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES THERETO AS AT AND FOR YEAR ENDED 31 DECEMBER 2013. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON 20 NOVEMBER 2014.

FORWARD LOOKING STATEMENTS

This management's discussion and analysis ("MD&A") contains forward-looking statements. More particularly, this MD&A contains statements concerning, but not limited to: repayment of the TANESCO receivables; the need for additional funding within the next year for the Company's ongoing operations if the Company is unable to collect the TANESCO receivables; the actions taken and to be taken by the Company to collect the TANESCO receivables; the Company's viability and its ability to meet its obligations as they come due; the potential taxes and penalties payable by the Company to the TRA, and the Company's beliefs regarding the assessments and the steps taken and to be taken by the Company to appeal and object to such assessments; status of negotiations with the TPDC regarding a sales agreement for incremental gas volumes and the Company's plans if an agreement is not reached in the near future; status of execution of a full field development plan for Songo Songo, including the anticipated gas sales volumes, the funding of the development plan, and the contingencies related to the development work; the targeted onstream date for the National Natural Gas Infrastructure Project; anticipated effect of the National Natural Gas Policy on the Company's rights under the PSA; and the Company's strategic plans. In addition, statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. The recovery and reserve estimates of Orca's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements. Although management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies.

These forward-looking statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Orca's control, and many factors could cause Orca's actual results to differ materially from those expressed or implied in any forward-looking statements made by Orca, including, but not limited to: failure to receive payments from TANESCO; failure to obtain adequate funding to meet the Company's obligations as they come due; failure to reach a sales agreement with TPDC for incremental gas volumes; potential negative effect on the Company's rights under the PSA as a result of the National Natural Gas Policy; risk that the contingencies related to the development work for the full field development plan for Songo Songo are not satisfied; risk that the onstream date for the National Natural Gas Infrastructure Project is delayed; failure to obtain funding for full field development plan for Songo Songo; risk that the Company will be required to pay additional taxes and penalties; the impact of general economic conditions in the areas in which Orca operates; civil unrest; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices; foreign exchange or interest rates; stock market volatility; competition for, among other things, capital, drilling equipment and skilled personnel; failure to obtain required equipment for drilling; delays in drilling plans; failure to obtain expected results from drilling of wells; effect of changes to the PSA on the Company; changes in laws; imprecision in reserve estimates; the production and growth potential of the Company's assets; obtaining required approvals of regulatory authorities; risks associated with negotiating with foreign governments; inability to access sufficient capital; failure to successfully negotiate agreements; and risk that the Company will not be able to fulfil its obligations. In addition there are risks and uncertainties associated with oil and gas operations, therefore Orca's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking estimates will transpire or occur, or if any of them do so, what benefits Orca will derive therefrom. Readers are cautioned that the foregoing list of factors is not exhaustive.

Such forward-looking statements are based on certain assumptions made by Orca in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors Orca believes are appropriate in the circumstances, including, but not limited to: that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company will have adequate funding to continue operations; that the Company will successfully negotiate agreements; receipt of required regulatory approvals; the ability of Orca to increase production at a consistent rate; infrastructure capacity; commodity prices will not deteriorate significantly; the ability of Orca to obtain equipment in a timely manner to carry out exploration, development and exploitation activities; future capital expenditures; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; the impact of increasing competition; conditions in general economic and financial markets; effects of regulation by governmental agencies; that the Company will obtain funding for full field development plan for Songo Songo; that the Company's appeal of the tax assessment by the TRA will be successful; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and other matters.

The forward-looking statements contained in this MD&A are made as of the date hereof and Orca undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

NON-GAAP MEASURES

THE COMPANY EVALUATES ITS PERFORMANCE USING A NUMBER OF NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) MEASURES. THESE NON-GAAP MEASURES ARE NOT STANDARDISED AND THEREFORE MAY NOT BE COMPARABLE TO SIMILAR MEASUREMENTS OF OTHER ENTITIES.

- **FUNDS FLOW FROM OPERATING ACTIVITIES** IS A TERM THAT REPRESENTS CASH FLOW FROM OPERATIONS BEFORE WORKING CAPITAL CHANGES. IT IS A KEY MEASURE AS IT DEMONSTRATES THE COMPANY'S ABILITY TO GENERATE CASH NECESSARY TO ACHIEVE GROWTH THROUGH CAPITAL INVESTMENTS.
- **OPERATING NETBACKS** REPRESENT THE PROFIT MARGIN ASSOCIATED WITH THE PRODUCTION AND SALE OF ADDITIONAL GAS AND IS CALCULATED AS REVENUES LESS PROCESSING AND TRANSPORTATION TARIFFS, GOVERNMENT PARASTATAL'S REVENUE SHARE, OPERATING AND DISTRIBUTION COSTS FOR ONE THOUSAND STANDARD CUBIC FEET OF ADDITIONAL GAS. THIS IS A KEY MEASURE AS IT DEMONSTRATES THE PROFIT GENERATED FROM EACH UNIT OF PRODUCTION, AND IS WIDELY USED BY THE INVESTMENT COMMUNITY.
- **FUNDS FLOW FROM OPERATING ACTIVITIES PER SHARE** IS CALCUALATED ON THE BASIS OF THE FUNDS FLOW FROM OPERATIONS DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.
- **CASH FLOW FROM OPERATING ACTIVITIES PER SHARE** IS CALCULATED AS CASH FLOW FROM OPERATIONS DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.

ADDITIONAL INFORMATION REGARDING ORCA EXPLORATION IS AVAILABLE UNDER THE COMPANY'S PROFILE ON SEDAR AT *www.sedar.com.*

BACKGROUND

Tanzania

The Company's principal operating asset is its interest in a Production Sharing Agreement ("PSA") with the Tanzania Petroleum Development Corporation ("TPDC") and the Government of Tanzania in the United Republic of Tanzania. This PSA covers the production and marketing of certain gas from the Songo Songo gas field.

The gas in the Songo Songo field is divided between Protected Gas and Additional Gas. The Protected Gas is owned by TPDC and is sold under a 20-year gas agreement (until July 2024) to Songas Limited ("Songas"). Songas is the owner of the infrastructure that enables the gas to be delivered to Dar es Salaam, which includes a gas processing plant on Songo Songo Island, 232 kilometres of pipeline to Dar es Salaam and a 16 kilometre spur to the Wazo Hill Cement Plant.

Songas utilizes the Protected Gas (maximum 45.1 MMcfd on any given day, non-cumulative) as feedstock for its gas turbine electricity generators at Ubungo, for onward sale to the Wazo Hill cement plant and for electrification of some villages along the pipeline route. The Company receives no revenue for the Protected Gas delivered to Songas and operates the field and gas processing plant on a 'no gain no loss' basis.

Under the PSA, the Company has the right to produce and market all gas in the Songo Songo field in excess of the Protected Gas requirements ("Additional Gas").

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PRINCIPAL TERMS OF THE TANZANIAN PSA AND RELATED AGREEMENTS

The principal terms of the Songo Songo PSA and related agreements are as follows:

Obligations and restrictions

(a) The Company has the right to conduct petroleum operations, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of 25 years, expiring in October 2026.

(b) The PSA covers the two licenses in which the Songo Songo field is located ("Discovery Blocks"). The Proven Section is essentially the area covered by the Songo Songo field within the Discovery Blocks.

(c) No sale of Additional Gas may be made from the Discovery Blocks, if in the Company's reasonable judgment, such sales would jeopardise the supply of Protected Gas. Any Additional Gas contracts entered into are subject to interruption. Songas has the right to request that the Company and TPDC obtain security reasonably acceptable to Songas prior to making any sales of Additional Gas from the Discovery Block to secure the Company's and TPDC's obligations in respect of Insufficiency (see (d) below).

(d) "Insufficiency" occurs if there is insufficient gas from the Discovery Blocks to supply the Protected Gas requirements or is so expensive to develop that its cost exceeds the market price of alternative fuels at Ubungo.

Where there have been third party sales of Additional Gas by the Company and TPDC from the Discovery Blocks prior to the occurrence of the Insufficiency, the Company and TPDC shall be jointly liable for the Insufficiency and shall satisfy its related liability by either replacing the Indemnified Volume (as defined in (e) below) at the Protected Gas price with natural gas from other sources; or by paying money damages equal to the difference between: (a) the market price for a quantity of alternative fuel that is appropriate for the five gas turbine electricity generators at Ubungo without significant modification together with the costs of any modification; and (b) the sum of the price for such volume of Protected Gas (at US$0.55/MMbtu escalated) and the amount of transportation revenues previously credited by Songas to the state electricity utility, the Tanzania Electric Supply Company ("TANESCO"), for the gas volumes.

(e) The "Indemnified Volume" means the lesser of the total volume of Additional Gas sales supplied from the Discovery Blocks prior to an Insufficiency and the Insufficiency Volume. "Insufficiency Volume" means the volume of natural gas determined by multiplying the average of the annual Protected Gas volumes for the three years prior to the Insufficiency by 110% and multiplied by the number of remaining years (initial term of 20 years) of the power purchase agreement entered into between Songas and TANESCO in relation to the five gas turbine electricity generators at Ubungo from the date of the Insufficiency.

Access and development of infrastructure

(f) The Company is able to utilise the Songas infrastructure including the gas processing plant and main pipeline to Dar es Salaam. Access to the pipeline and gas processing plant is open and can be utilised by any third party who wishes to process or transport gas. Ndovu Resources Limited, a subsidiary of Aminex PLC, with support from TPDC and the Ministry of Energy and Mines, had previously indicated that it wished to tie into the gas processing plant on Songo Songo Island and sell up to 10 MMcfd from its Kiliwani North field. Aminex announced in October 2013 that it has engaged in negotiations with TPDC leading to a gas sales agreement which would provide for gas from Kilwa North to be tied in to the new National Natural Gas Infrastructure Project ("NNGIP") facilities on Songo Songo Island and not be connected into the Songas facilities.

Songas is not required to incur capital costs with respect to additional processing and transportation facilities unless the construction and operation of the facilities are, in the reasonable opinion of Songas, financially viable. If Songas is unable to finance such facilities, Songas shall permit the seller of the gas to construct the facilities at its expense, provided that, the facilities are designed, engineered and constructed in accordance with good pipeline and oilfield practices.

Revenue sharing terms and taxation

(g) 75% of the gross revenues, less processing and pipeline tariffs and direct sales taxes in any year ("Net Revenues"), can be used to recover past costs incurred. Costs recovered out of Net Revenues are termed "Cost Gas".

The Company pays and recovers costs of exploring, developing and operating the Additional Gas with two exceptions: (i) TPDC may recover reasonable market and market research costs as defined under the PSA; and (ii) TPDC has the right to elect to participate in the drilling of at least one well for Additional Gas in the Discovery Blocks for which there is a development program as detailed in an Additional Gas plan ("Additional Gas Plan") as submitted to the Ministry of Energy and Minerals ("MEM"), subject to TPDC being able to elect to participate in a development program only once and TPDC having to pay a proportion of the costs of such development program by committing to pay between 5% and 20% of the total costs ("Specified Proportion"). If TPDC does not notify the Company within 90 days of notice from the Company that the MEM has approved the Additional Gas Plan, then TPDC is deemed not to have elected. If TPDC elects to participate, then it will be entitled to a rateable proportion of the Cost Gas and their profit share percentage increases by the Specified Proportion for that development program.

To date, TPDC has neither elected to back in within the prescribed notice period nor contributed any costs associated with backing in and accordingly the Company has determined that to date there has been no working interest earned by TPDC. TPDC back-in rights and the potential conversion of these rights into a carried working interest were discussed with the GNT along with other issues; however nothing was agreed between the parties. Until such time as an agreement is reached, the Company will apply the terms of the original PSA. Should an amendment to the PSA be agreed in future relating to back-in rights, the impact on reserves and accounting estimates will be assessed at that time and reflected prospectively. For the purpose of the reserves certification as at 31 December 2013, it was assumed that TPDC will 'back-in' for 20% for all future new drilling activities as determined by the current development plan and this is reflected in the Company's net reserve position.

(h) In 2009, the energy regulator, Energy and Water Utility Regulatory Authority ("EWURA"), issued an order that saw the introduction of a flat rate tariff of US$0.59/mcf from 1 January 2010. The Company's long-term gas price to the Power sector as set out in the initialled Amended and Restated Gas Agreement ("ARGA") and the Portfolio Gas Supply Agreement ("PGSA") is based on the price of gas at the wellhead. As a consequence, the Company is not impacted by the changes to the tariff paid to Songas or other operators in respect of sales to the Power sector.

In 2011, the Company signed a re-rating agreement with TANESCO and Songas (the "Re-Rating Agreement") to increase the gas processing capacity to a maximum of 110 MMcfd (the pipeline and pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-rating Agreement, the Company effectively pays an additional tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA.

Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15 million, but only to the extent that this was not already covered by indemnities from TANESCO or Songas' insurance policies. The Re-rating Agreement expired on 31st December 2012 and in September 2013 was extended by Songas to 31 December 2013. At this time the Company knows of no reason to de-rate the Songas plant. Since then production has continued at the higher rated limit and, given the Government's interest in pursuing further development and increasing gas production, the Company expects this to continue. However there are no assurances that this will occur.

(i) The cost of maintaining the wells and flowlines is split between the Protected Gas and Additional Gas users in proportion to the volume of their respective sales. The cost of operating the gas processing plant and the pipeline to Dar es Salaam is covered through the payment of the pipeline tariff.

(j) Profits on sales from the Proven Section ("Profit Gas") are shared between TPDC and the Company, the proportion of which is dependent on the average daily volumes of Additional Gas sold or cumulative production.

The Company receives a higher share of the net revenues after cost recovery, based on the higher the cumulative production or the average daily sales. The Profit Gas share is a minimum of 25% and a maximum of 55%.

Average daily sales of Additional Gas	Cumulative sales of Additional Gas	TPDC's share of Profit Gas	Company's share of Profit Gas
MMcfd	*Bcf*	*%*	*%*
0 - 20	0 – 125	75	25
> 20 <= 30	> 125 <= 250	70	30
> 30 <= 40	> 250 <= 375	65	35
> 40 <= 50	> 375 <= 500	60	40
> 50	> 500	45	55

For Additional Gas produced outside of the Proven Section, the Company's Profit Gas share is 55%.

Where TPDC elects to participate in a development program, its profit share percentage increases by the Specified Proportion (for that development program) with a corresponding decrease in the Company's percentage share of Profit Gas.

The Company is liable to income tax in Tanzania. Where income tax is payable, the Company pays the tax and there is a corresponding deduction in the amount of the Profit Gas payable to TPDC.

(k) Additional Profits Tax ("APT") is payable where the Company has recovered its costs plus a specified return out of Cost Gas revenues and Profit Gas revenues. As a result: (i) no APT is payable until the Company recovers its costs out of Additional Gas revenues plus an annual operating return under the PSA of 25%, plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"); and (ii) the maximum APT rate is 55% of the Company's Profit Gas when costs have been recovered with an annual return of 35% plus PPI return. The PSA is, therefore, structured to encourage the Company to develop the market and the gas fields in the knowledge that the Profit Gas share can increase with larger daily gas sales and that the costs will be recovered with a 25% plus PPI annual return before APT becomes payable. APT can have a significant negative impact on the project economics if only limited capital expenditure is incurred.

Operatorship

(l) The Company is appointed to develop, produce and process Protected Gas and operate and maintain the Songas gas production facilities and processing plant, including the staffing, procurement, capital improvements, contract maintenance, maintain books and records, prepare reports, maintain permits, handle waste, liaise with the Government of Tanzania and take all necessary safety, health and environmental precautions, all in accordance with good oilfield practices. In return, the Company is paid or reimbursed by Songas so that the Company neither benefits nor suffers a loss as a result of its performance.

(m) In the event of loss arising from Songas' failure to perform and the loss is not fully compensated by Songas, the Company, or insurance coverage, then the Company is liable to a performance and operation guarantee of US$2.5 million when (i) the loss is caused by the gross negligence or wilful misconduct of the Company, its subsidiaries or employees, and (ii) Songas has insufficient funds to cure the loss and operate the project.

Consolidation

The companies, which are 100% owned, that are being consolidated are:

Company	Incorporated
Orca Exploration Group Inc.	British Virgin Islands
Orca Exploration Italy Inc.	British Virgin Islands
Orca Exploration Italy Onshore Inc.	British Virgin Islands
PAE PanAfrican Energy Corporation	Mauritius
PanAfrican Energy Tanzania Limited	Jersey
Orca Exploration UK Services Limited	United Kingdom

Results for the three months and nine months ended 30 September 2014

OPERATING VOLUMES

The total production volume of Protected Gas and Additional Gas for the quarter ended 30 September 2014 was 8,545 MMcf (Q3 2013: 8,841 MMcf) or 92.9 MMcfd (Q3 2013: 97.1 MMcfd), net of approximately 0.8 MMcfd (Q3 2013: 0.4 MMcfd) consumed locally for fuel gas. The Additional Gas sales volumes for the quarter were 5,239 MMcf (Q3 2013: 6,045 MMcf) or average daily volumes of 57.0 MMcfd (Q3 2013: 65.7 MMcfd). This represents a decrease in average daily volumes of 13% over the prior year and an increase of 14% over the prior quarter, Q2 2014 (50.0 MMcfd).

The Company's sales volumes were split between the Industrial and Power sectors as follows:

	Three months ended		*Nine months ended*	
	30 Sept 2014	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Gross sales volume *(MMcf)*				
Industrial sector	**1,304**	1,092	**3,514**	3,335
Power sector	**3,935**	4,953	**11,446**	13,566
Total volumes	**5,239**	6,045	**14,960**	16,901
Gross daily sales volume *(MMcfd)*				
Industrial sector	**14.2**	11.9	**12.9**	12.2
Power sector	**42.8**	53.8	**41.9**	49.7
Total daily sales volume	**57.0**	65.7	**54.8**	61.9

Industrial sector

Current quarter Industrial sales volume increased by 19% to 1,304 MMcf (14.2 MMcfd) from 1,092 MMcf (11.9 MMcfd) in Q3 2013. The increase is primarily due to increased gas consumption by the cement, cigarette and some textile companies to their normal consumption levels which offset the decrease gas consumption by a glass company as a consequence of extended maintenance work. Industrial gas volumes increased by 25% over Q2 2014 (1,046 MMcf or 11.5 MMcfd) due to completion of maintenance work at the cement producer and a glass company. The Industrial sales have increased by 5% in the first nine months of 2014 comparing to those of 2013. The increase is primarily due to increased consumption by the cement, textile and some other companies as a result of completion of maintenance work that off-set reduction in gas consumption by the glass company which was still undergoing some maintenance work in Q3 2014.

Power sector

Power sector sales volumes decreased by 21% to 3,935 MMcf or 42.8 MMcfd, compared to 4,953 MMcf or 53.8 MMcfd in Q3 2013 as a result of the increased availability of hydroelectricity leading to a reduction in demand for natural gas-fired power compared with the same period in 2013. Power sales volumes were up 12% over Q2 2014 (3,503 MMcf or 38.5 MMcfd) principally as a result of increased nominations by TANESCO as the benefits of seasonally available hydro decreased during the period. Sales volume to the power sector in the first nine months of 2014 have decreased by 16% comparing to the same period in 2013 again due to increased availability of hydroelectricity as a result of heavy rains in Q2 2014.

SONGO SONGO DELIVERABILITY

As at 30 September 2014, the Company had a field productive capacity of approximately 93 MMcfd, with expansion of production volumes limited to 102 MMcfd by the available Songas infrastructure. Production wells SS-3, SS-5 and SS-9 remain suspended pending workovers. SS-4 continues to be monitored and it may have to be suspended in the future.

There remains no redundant productive capacity until additional wells can be drilled in the field, or existing wells can be worked over or until compression facilities are installed. A loss or material reduction in the production of any given well will have a material adverse effect on the total production and funds flow from operations of the Company.

Significant additional capital expenditure will be required to enable the Songo Songo field to produce 190 MMcfd in line with the anticipated infrastructure expansion requirements. There are no contractual commitments either in the PSA or otherwise agreed for capital expenditure at Songo Songo. Any significant additional capital expenditure by the Company in Tanzania is discretionary and remains dependent on: (i) agreeing commercial terms with TPDC or other buyers regarding the sale of incremental gas volumes from Songo Songo; (ii) TANESCO receivables being brought up to date, guaranteed or other arrangements for payment satisfactory to the Company, (iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any contracts with Government entities; and (iv) the arrangement of finance with the IFC or other lenders.

Whilst the Company continues to refine a full field development plan based on expanded infrastructure submitted to the Ministry of Energy and Minerals ("MEM") during 2013, the Company does not intend to proceed with the plan until the issues outlined above are resolved.

COMMODITY PRICES

The commodity prices achieved in the Industrial and Power sectors during the quarter are shown in the table below:

	Three months ended		*Nine months ended*	
US$/mcf	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Average sales price				
Industrial sector(1)	**8.85**	8.43	**8.73**	8.24
Power sector	**3.60**	4.10	**3.58**	3.78
Weighted average price(1)	**4.91**	4.88	**4.79**	4.66

(1) In Q3 2014 the Company recognized income of US$1.2 million (nine months to 30 September 2014 US$3.3 million) deferred under a take-or-pay provision in an Industrial contract. Under the contract the customer has three years in which to utilise the deferred income, after which it is released to revenue. These amounts been deducted from revenue in calculating the average sales prices achieved in the quarter.

Industrial sector

The average Industrial gas price for the quarter was US$8.85/mcf up 5% from Q3 2013 (US$8.43/mcf) but down 5% from Q2 2014 (US$9.27/mcf). The increase over the same period for the prior year is the result of annual price indexation which is applied in January each year and a decrease in the proportion of lower priced sales volumes in the total Industrial sales mix. The decrease in Industrial prices from Q2 2014 to Q3 2014 is a result of a change in sales mix and a 2% decrease in heavy fuel oil ("HFO") prices. The average price for the first nine months of 2014 was US$8.73/mcf up 6% from US$8.24/mcf for the same period in 2013. The increase is the result of annual price indexation and a decrease in the proportion of lower priced sales volumes whilst HFO prices decreased approximately 3%.

Power sector

The average sales price to the Power sector was US$3.60 for the quarter, down 12% compared with US$4.10/mcf in the prior year period, and down 1% compared to the Q2 2014 price of US$3.65/mcf. The decreases are the result of reduced sales volumes to the Power sector which in turn reduced the amount of sales subject to premium pricing in accordance with the PGSA which offset the impact of annual price indexation which is applied in July each year. Higher volumes in both prior comparative periods, Q3 2013 and Q2 2014, resulted in a larger proportion being sold at a higher price, in accordance with the PGSA. The average price to the Power sector for the first nine months of 2014 was US$3.58/mcf down 5% compared to US$3.78/mcf for the same period in 2013. The decrease is due to a reduction in the sales volume subject to the escalated well head price which more than offset annual price indexation.

OPERATING REVENUE

Under the terms of the Songo Songo PSA, the Company is responsible for invoicing, collecting and allocating the revenue from Additional Gas sales.

The Company is able to recover all costs incurred on the exploration, development and operations of the project out of 75% of the Net Revenues ("Cost Gas") prior to the distribution of Profit Gas. Any costs not recovered in any period are carried forward for recovery out of future revenues. Once the Cost Gas has been recovered, TPDC is able to recover any pre-approved marketing costs.

The Additional Gas sales volumes for Q3 2014 and the prior periods were in excess of 50 MMcfd entitling the Company to a 55% share of Profit Gas Revenue (net of Cost Gas recoveries from revenue).

The Company's share of revenue for the nine months includes an adjustment to the Cost Pool in respect of downstream costs incurred in prior years and a further adjustment relating to non-recoverable items agreed by the Company in the course of settling the TPDC Cost Pool audit. See separate note – Cost Pool Adjustment below.

The Company was allocated a total of 60.3% of Net Revenue in Q3 2014 (Q3 2013: 58.8%), before taking into account the Cost Pool adjustment as follows:

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Gross sales revenue	**26,898**	29,524	**74,965**	78,720
Gross tariff for processing plant and pipeline infrastructure	**(3,680)**	(4,377)	**(10,521)**	(12,284)
Gross revenue after tariff ("Net Revenues")	**23,218**	25,147	**64,444**	66,436
Analysed as to:				
Company Cost Gas	**2,751**	2,847	**8,994**	8,041
Company Profit Gas	**11,256**	11,950	**30,498**	31,241
Cost Pool adjustment	**–**	–	**2,994**	–
Company operating revenue	**14,007**	14,797	**42,486**	39,282
TPDC share of revenue	**9,211**	10,350	**21,958**	27,154
	23,218	25,147	**64,444**	66,436

The Company's total revenues for the quarter, and the nine months ended 30 September 2014, amounted to US$14,852 and US$47,624 respectively, after adjusting the Company's operating revenues of US$ 14,007 and US$42,486 by:

i) adding US$3,355 for income tax for the current period, and US$10,989 for the nine months. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenue is adjusted to include the current income tax charge grossed up at 30%; and,

ii) subtracting US$2,510 and US$5,851 for deferred Additional Profits Tax charged in the quarter and for nine months– this tax is considered a royalty and is presented as a reduction in revenue. The nine month APT charge includes a reduction in APT of US$936 resulting from the recovery of downstream costs previously and temporarily excluded from the cost recoverable pool. See note on Cost Pool adjustments below.

Revenue presented on the Condensed Consolidated Interim Statement of Comprehensive Income may be reconciled to the operating revenue as follows:

	Three months ended		Nine months ended	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Industrial sector	**12,737**	9,182	**33,938**	27,462
Power sector	**14,161**	20,342	**41,027**	51,258
Gross sales revenue	**26,898**	29,524	**74,965**	78,720
Processing and transportation tariff	**(3,680)**	(4,377)	**(10,521)**	(12,284)
TPDC share of revenue	**(9,211)**	(10,350)	**(21,958)**	(27,154)
Company operating revenue	**14,007**	14,797	**42,486**	39,282
Additional Profits Tax charge	**(2,510)**	(3,979)	**(5,851)**	(10,404)
Current income tax adjustment	**3,355**	3,841	**10,989**	10,975
Revenue	**14,852**	14,659	**47,624**	39,853

Company operating revenue decreased 5% in the quarter compared with Q3 2013. The decrease is the result of several factors. A 13% decrease in sales volumes which offset a 1% increase in weighted average gas price, have contributed to an overall 9% decrease in gross sales revenue. This was offset by lower tariff charges, increased operating expenses which further reduced TPDC's share of revenue. The rise in revenue for the period is due to reduced APT expense, compared to the three months ended 30 September 2013, resulting from the increased scope of investment contemplated in the new development plan and, thus, a lower effective APT rate of 22.3% (Q3 2013: 33.3%); total APT expected to be paid over the life of the license is lower – see "Additional Profits Tax" below.

Company operating revenue for the nine months ended 30 September 2014 is up 8% as a result of the US$3.0 million Cost Pool adjustment in Q2 2014. A reduction of US$4.6 million in the APT charge resulted in an overall increase in Revenue of 19%. US$0.9 million of the APT reduction is attributable to the Cost Pool adjustment the balance to the lower effective rate of APT in the current year.

Cost Pool Adjustments

In 2010, following an agreement with TPDC the Company agreed to temporarily defer the cost recovery of expenditure associated with development of the downstream network until such time as a mutually acceptable methodology could be agreed between the Company and TPDC/MEM to unbundle the downstream assets and related business and to recover the associated cost of the operation outside of the PSA. In 2013 the Company re-tabled a number of proposals that were economically neutral to the parties; however these received no feedback and were subsequently withdrawn. The Company has formally advised TPDC that the downstream business will remain under the PSA and that related costs would be recovered in accordance with the terms of the PSA and would no longer be held separately. As a result of recovering this expenditure there has been a reallocation of Cost Gas and Profit Gas between TPDC and the Company.

During the ongoing discussions concerning the disputed US$34 million TPDC Cost Pool audit claim, items totalling US$1.0 million were agreed by the Company as non-recoverable and consequently were removed from the Cost Pool in the second quarter of 2014.

The following table shows the impact on the Company's operating revenue, for the nine months to 30 September 2014, of adjusting the cost pool. The net amount was recovered from TPDC's share of revenue in the second quarter as follows:

US$'000	**Nine months ended 30 September 2014**
Non-recoverable costs	(1,024)
Recoverable costs 2011-2013	7,360
Cost Gas recorded in the period	6,336
Reduction in Profit Gas in the period	(3,342)
Net impact on Company share of operating revenue	2,994

PROCESSING AND TRANSPORTATION TARIFF

The Company pays a tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the regulated tariff of US$0.59/mcf payable to Songas. The Q3 2014 charge for the additional tariff was US$0.6 million (Q3 2013: US$0.8 million).

PRODUCTION AND DISTRIBUTION EXPENSES

The well maintenance costs are allocated between Protected and Additional Gas in proportion to their respective sales during the period. The total cost of maintenance for the period was US$125 (Q3 2013: US$172) of which US$79 (Q3 2013: US$116) was allocated for the Additional Gas. The decrease in the current period costs is a result of focusing on engineering and planning in respect of SS-5 and SS-9 well workovers.

Other field and operating costs include an apportionment of the annual PSA licence costs, regulatory fees and some costs associated with the evaluation of the reserves, and the cost of personnel which are not recoverable from Songas.

Distribution costs represent the direct cost of maintaining the ring main distribution pipeline and pressure reduction station (security, insurance and personnel). Ring main distribution costs were US$615 in the current quarter (Q3 2013: US$605), the increase for the nine months to 30 September is partly as a result of increased activity, and partly as a result of reclassifying costs in Q2 2013. These production and distribution costs are summarized in the table below:

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Share of well maintenance	**79**	116	**519**	274
Other field and operating costs	**485**	429	**1,586**	1,199
	564	545	**2,105**	1,473
Ring main distribution costs	**615**	605	**1,720**	1,091
Production and distribution expenses	**1,179**	1,150	**3,825**	2,564

OPERATING NETBACKS

The netback per mcf before general and administrative costs, overhead, tax and APT may be analysed as follows:

	Three months ended		*Nine months ended*	
US$/mcf	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Gas price – Industrial	**8.85**	8.43	**8.73**	8.24
Gas price – Power	**3.60**	4.10	**3.58**	3.78
Weighted average price for gas	**4.91**	4.88	**4.79**	4.66
Tariff	**(0.70)**	(0.72)	**(0.70)**	(0.73)
TPDC share of revenue	**(1.76)**	(1.71)	**(1.47)**	(1.61)
Net selling price	**2.45**	2.45	**2.62**	2.32
Well maintenance and other operating costs	**(0.11)**	(0.09)	**(0.14)**	(0.09)
Distribution costs	**(0.12)**	(0.10)	**(0.12)**	(0.06)
Operating netback	**2.22**	2.26	**2.36**	2.17

The operating netback for the quarter decreased by 2% from US$2.26/mcf in Q3 2013 to US$2.22/mcf in Q3 2014; this was the result of several factors. Lower Power sales volumes led to a reduction in sales at premium prices and a 12% drop in the average price, largely offsetting the effect of indexation in July and the effect of a 5% increase in the weighted average Industrial gas price. The 3% increase in the TPDC share of revenue on a unit basis is a direct result of the lower sales volume.

The operating netback for the nine months is essentially unchanged. An 11% fall in volumes was offset by a 3% increase in the weighted average price resulting in a 5% drop in gross revenue. On a per Mcf basis TPDC's share of revenue dropped 9%, this is largely attributable to the recovery of downstream costs in Q2 which accounted for US$0.20/mcf. However, this was offset by increases in field operating and distribution costs.

GENERAL AND ADMINISTRATIVE EXPENSES

The general and administrative expenses ("G&A") may be analysed as follows:

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Employee & related costs	**1,343**	1,635	**4,497**	5,118
Stock based compensation	**4,221**	24	**4,583**	(289)
Office costs	**1,004**	1,302	**2,600**	2,823
Marketing & business development costs	**48**	146	**66**	735
Reporting, regulatory & corporate	**859**	220	**2,880**	1,900
General and administrative expenses	**7,475**	3,327	**14,626**	10,287

G&A includes the costs of running the natural gas distribution business in Tanzania which is recoverable as Cost Gas and which is relatively fixed in nature. The increase in reporting, regulatory and corporate expenses is primarily the result of additional legal costs associated with the various contractual and dispute resolution matters which are ongoing. Excuding stock based compensation, G&A averaged approximately US$1.08 million per month during the third quarter of 2014 and US$1.10 million per month in 2013. The rate per mcf for the current quarter was US$1.43/ mcf (Q3 2013: US$0.55/mcf) and for the nine months ended 30 September 2014 US$0.98/mcf (2013: US$0.61/mcf). The unit rates, excluding stock based compensation, were US$0.62/mcf (Q3 2013: US$0.55 /mcf) and US$0.67 /mcf (2013: US$0.63/mcf) for the quarter and nine months respectively; increases over 2013 being attributable to lower volumes.

STOCK-BASED COMPENSATION

The breakdown of the costs incurred in relation to stock based compensation is detailed in the table below:

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Stock appreciation rights	1,544	24	1,906	(289)
Restricted stock units	2,677	–	2,677	–
Stock-based compensation	4,221	24	4,583	(289)

400,000 stock options were outstanding as at 30 September 2014 compared to 1,742,400 at the end of 2013.

No options were granted during the quarter (Q3 2013: nil).

2,810,000 stock appreciation rights ("SARs") were outstanding as at 30 September 2014 compared to 1,030,000 as at 31 December 2013. 1,780,000 SARs were granted in January with an exercise price of CDN$2.30, a five-year term and which vest in five equal instalments, the first fifth on the anniversary of the grant date.

In September the Company issued 792,391 Restricted Stock Units ("RSUs") with an award price of CDN$0.01.

As SARs and RSUs are settled in cash, they are re-valued at each reporting date using the Black-Scholes option pricing model with the resulting liability being recognised in trade and other payables. In the valuation of stock appreciation rights and restricted stock units at the reporting date, the following assumptions have been made: a risk free rate of interest of 1.75%; stock volatility of 51.9% to 59.6%; 0% dividend yield; 0% forfeiture; and a closing price of CDN$3.79 per Class B share.

As at 30 September 2014, a total accrued liability of US$5.0 million (Q3 2013: US$0.3 million) has been recognised in relation to SARs and RSUs. The Company recognised an expense of US$4.2 million (Q3 2013: nil) for the quarter and for the nine months ended 30 September 2014 an expense of US$4.6 million (2013: credit US$0.3 million). The increase in the cost of SARs year over year is due to the granting of an additional 1.8 million SARs in January 2014 and an increase in the market value of the Company's shares.

NET FINANCE COSTS

The movement in net financing costs is summarized in the table below:

	Three months ended		Nine months ended	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Interest charged on overdue trade receivables	**465**	289	**1,747**	2,155
Finance income	**465**	289	**1,747**	2,155
Interest expense	**–**	(157)	**(24)**	(586)
Net foreign exchange loss	**164**	633	**(453)**	(1,138)
Discount of long-term receivable	**–**	(2,900)	**–**	(10,800)
Provision for doubtful debts	**(459)**	(1,200)	**(3,665)**	(8,300)
Finance costs	**(295)**	(3,624)	**(4,142)**	(20,824)
Net finance income/expense	**170**	(3,335)	**(2,395)**	(18,669)

Interest of US$0.5 million for the quarter (Q3 2013: US$0.3 million) and US$1.7 million (2013: US$2.2 million) for the nine months ended 30 September was charged to TANESCO under the terms of the PGSA for late payment of gas supplied and has been fully provided against to reflect the uncertainty over timing of collection.

The decrease in interest expense is the result of repaying the bank loan in full by the end of February 2014.

The foreign exchange gain/loss reflects the impact of movements in the value of the Tanzanian Shilling against the US Dollar during the period on outstanding customer/supplier balances and bank accounts denominated in Tanzanian Shillings.

As at 30 September 2014, Songas owed the Company US$39.4 million (Q4 2013: US$24.8 million), whilst the Company owed Songas US$27.4 million (Q4 2013: US$16.9 million). There is no contractual right to offset these amounts at 30 September 2014. Amounts due to Songas primarily relate to pipeline tariff charges of US$25.8 million (Q4 2013: US$15.4 million), whereas the amounts due to the Company are mainly for sales of gas of US$20.6 million (Q4 2013: US$11.6 million) and for the operation of the gas plant for US$18.8 million (Q4 2013: US$13.3 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis without profit margin.

Following an extended period during which no cash was received and no balances set-off, the Company was unable to recognise the Songas receivable. Accordingly, as at 31 March 2014 the Company had fully provided for the net amount due from Songas. However, during the quarter Songas made two payments totalling US$0.8 million in response to cash calls for July and August 2014, and subsequent to the quarter end has made a further three payments totalling US$1.2 million in respect of September, October and November. Management is continuing to work with Songas towards an agreement to set-off outstanding sales, purchases and gas plant operating charges. As a result no additional provision has been made against the net Songas receivable. The existing provision will be released as and when the Company is able to collect the outstanding debt. Any amounts which are not agreed will be pursued by the Company through the dispute mechanisms provided in its agreements with Songas.

Management continues to believe that TANESCO will ultimately settle its debts with the Company. Whilst during Q2 2014 TANESCO commenced a series of payments approximately weekly, as at the date of this report the Company has not agreed a formal set schedule or repayment plan for TANESCO arrears and payments have been irregular and unpredictable since mid-2011. Subsequent to the quarter end TANESCO has only made one payment of US$1.8 million. As a result there continues to be significant doubt about TANESCO's ability to settle current and arrears and the Company's ability to continue as a going concern. Based on the actual repayment history as at 30 September 2014 US$9.6 million (Q4 2013: US$9.6 million) of the TANESCO receivable was classified as current and US$45.0 million (Q4 2013: US$47.0 million) was classified as long-term. A discount of US$17.1 million (Q4 2013: US$17.1 million) has been taken against the long-term receivable to reflect the estimated cost of delays in collection. The long-term portion of the trade receivable was discounted using a risk adjusted discount rate of 15% to reflect the cost of delayed timing of collections from TANESCO. The discount rate and the expected timing of the collections are reviewed at each period end with any adjustments recorded in the period that the estimates change.

TAXATION

Income Tax

Under the terms of the PSA with TPDC and the Government of Tanzania, the Company is liable for income tax in Tanzania at the corporate tax rate of 30%. However, where income tax is payable, this is recovered from TPDC by deducting an amount from TPDC's share of Profit Gas. This is reflected in the accounts by increasing the Company's revenue by the appropriate amount.

As at 30 September 2014, there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes under the *Income Tax Act 2004*. Applying the 30% Tanzanian tax rate, the Company has recognised a deferred tax liability of US$12.3 million (31 December 2013: US$12.1 million). This represents no change in the deferred future income tax charge during the quarter compared with a reduction of US$0.8 million in Q3 2013. The deferred tax charge for the nine months ended 30 September was US$0.2 million compared to a reduction of US$5.8 million in 2013. The deferred tax has no impact on cash flow until it becomes a current income tax, at which point the tax is paid and recovered from TPDC's share of Profit Gas.

ADDITIONAL PROFITS TAX

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.

The timing and the effective rate of APT depends on the realised value of Profit Gas which in turns depends of the level of expenditure. The Company provides for APT by forecasting annually the total APT payable as a proportion of the forecast Profit Gas over the term of the PSA. The forecast takes into account the timing of future development capital spending.

The effective APT rate of 22.3% (Q3 2013: 33.3%) has been applied to Profit Gas of US$11.3 million (Q3 2013: US$12.0 million) for the quarter and US$30.5 million (2013: US$31.2 million) for the nine months ended 30 September 2014. Accordingly, US$2.5 million (Q3 2013: US$4.0 million) and US$5.9 million (2013: US$10.4 million) has been netted off revenue for the quarter and for the nine months ended 30 September 2014. The year-to-date APT charge includes a reduction of US$0.9 million, reflecting the impact of recovering downstream costs on cumulative Profit Gas, as a result of the US$3.3 million Profit Gas adjustment identified in the Cost Pool adjustment detailed above.

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Current APT payable	**2,630**	–	**5,094**	–
Deferred APT	**(120)**	3,979	**757**	10,404
	2,510	3,979	**5,851**	10,404

The deferred APT credit represents the release of an accumulated provision bringing the APT rate down from 25% to currently projected rate for the life of the PSA.

DEPLETION AND DEPRECIATION

The Natural Gas Properties are depleted using the unit of production method based on the production for the period as a percentage of the total future production from the Songo Songo proven reserves. As at 31 December 2013 the proven reserves estimated to be produced over the term of the PSA licence, as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd., were 476 Bcf. A depletion expense of US$3.7 million (Q3 2013: US$3.0 million) for the quarter and US$10.4 million (2013: US$8.3 million) for the nine months to 30 September 2014 has been recorded in the accounts; the increase is the result of a 13% decrease in sales volumes and a 43% increase in the depletion rate to US$0.70/mcf (Q3 2013: US$0.49/mcf).

Non-Natural Gas Properties are depreciated as follows:

Leasehold improvements	**Over remaining life of the lease**
Computer equipment	3 years
Vehicles	3 years
Fixtures and fittings	3 years

CARRYING AMOUNTS OF ASSETS

Capitalised costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that these capitalised costs are unlikely to be recovered in the future, they are impaired and recorded in the statement of comprehensive income.

FUNDS GENERATED BY OPERATIONS

Funds from operations before working capital changes were US$8.3 million for Q3 2014 (Q3 2013: US$12.0 million).

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Funds flow from operating activities	**8,288**	12,009	**28,658**	31,605
Working capital adjustments	**15,789**	2,630	**3,335**	(14,094)
Cash flows from operating activities	**24,077**	14,639	**31,993**	17,511
Cash used in investing activities	**(324)**	(744)	**(594)**	(1,152)
Cash from/(used in) financing activities	**92**	(2,291)	**(1,591)**	(1,530)
Increase in cash	**23,845**	11,446	**29,808**	14,243
Effect of change in foreign exchange on cash in hand	**577**	78	**720**	(89)
Net increase in cash	**24,422**	11,524	**30,528**	14,154

Operating revenues with respect to TANESCO and Songas are not fully reflected in the overall cash position as a consequence of the failure of both TANESCO and Songas to pay their invoices in full during the period.

CAPITAL EXPENDITURE

The Company incurred US$0.3 million in relation to engineering and planning relating to workovers of SS-5 and SS-9 and subsequent drilling activities.

	Three months ended		*Nine months ended*	
US$'000	**30 Sept 2014**	**30 Sept 2013**	**30 Sept 2014**	**30 Sept 2013**
Geological and geophysical and well drilling	**292**	391	**292**	762
Pipelines and infrastructure	**–**	296	**83**	327
Other equipment	**32**	57	**219**	61
	324	744	**594**	1,150

WORKING CAPITAL

Working capital as at 30 September 2014 was US$49.6 million (31 December 2013: US$27.8 million) and may be analysed as follows:

				As at
US$'000	**30 Sept 2014**		**31 Dec 2013**	
Cash		**63,116**		32,588
Trade and other receivables		**44,232**		37,215
TANESCO	**9,591**		9,624	
Songas	**20,556**		11,560	
Other trade debtors	**8,001**		10,874	
Songas gas plant operations	**18,783**		13,280	
Other receivables	**1,496**		2,408	
Provision for doubtful accounts	**(14,195)**		(10,531)	
Tax receivable		**15,975**		14,585
Prepayments		**512**		281
		123,835		84,669
Trade and other payables		**69,123**		53,296
TPDC	**28,026**		20,644	
Songas payables	**25,784**		15,355	
Other trade payables	**1,289**		3,857	
Deferred income	**3,674**		6,271	
Accrued liabilities	**10,350**		7,169	
Related parties	**–**		–	
Bank loan		**–**		1,659
Tax payable		**–**		1,958
Current APT payable		**5,094**		
Working capital (1)		**49,618**		27,756

Notes:

(1) Working capital as at 30 September 2014 includes a TANESCO short-term receivable of US$9.6 million (31 December 2013: US$9.6 million). Given the payment pattern, the TANESCO receivables in excess of 60 days which total US$45.0 million (31 December 2013: US$47.0 million) have been classified as long-term receivables and discounted by US$17.1 million. Total long- and short-term TANESCO receivables as at 30 September 2014 were US$54.6 million prior to discounting. Subsequent to the quarter end, TANESCO paid US$1.8 million, and as at 20 November 2014 the TANESCO balance was US$56.4 million of which arrears total US$52.8 million.

Working capital as at 30 September 2014 increased by 79% over 31 December 2013 and 33% during the quarter, primarily as a result of regular payments by TANESCO. The Company did not incur any major capital expenditure during the quarter. Other significant points are:

- At 30 September 2014 the majority of the Company's cash was held in Tanzania. There are no restrictions on the movement of cash from Mauritius or Tanzania.
- Since the quarter end the Company has received US$1.8 million from TANESCO. Management remains confident that the full amount due from TANESCO will ultimately be received.
- Of the US$8.0 million relating to other trade debtors US$3.9 million had been received as at the date of this report. Management expects to receive the balance during the course of Q4.
- The balance of US$28.0 million payable to TPDC represents the remaining balance of its share of revenue as at 30 September 2014.

BANK LOAN

The loan was fully paid by February 2014. Total payments during the nine months ended 30 September 2014 were US$1.7 million.

GOING CONCERN

These financial statements have been prepared on a going concern basis. The going concern basis of presentation assumes that the Company will continue in operation for the foreseeable future and be able to realize its assets and discharge its liabilities and commitments in the normal course of business. The financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying amounts of assets and liabilities, the reported revenues and expenses, and the balance sheet classifications.

The ability of the Company to continue as a going concern is dependent on the Company's ability to collect its receivables from Government entities to fund on-going operations and the exploration and development program. The continuing weakness in the financial position of the state utility, TANESCO, has created uncertainty as to whether the Company will be able to collect the amounts owing and to continue operations and meet its commitments. Beginning in May 2014, TANESCO commenced a series of payments for current and past gas deliveries of US$1.8 million received approximately weekly. Management estimates these continued payments would result in approximately US$1.5 million per month credited against arrears. As of the date of this report, however, there is no set schedule or repayment plan for TANESCO arrears agreed with the Company and payments since mid-2011 have been irregular and unpredictable. Subsequent to the quarter end TANESCO has only made one payment of US$1.8 million. As a result, there continues to be significant doubt about TANESCO's ability to settle current and arrears and the Company's ability to continue as a going concern.

In the event that the Company does not collect from TANESCO the balance of the outstanding receivables at 30 September 2014, and TANESCO continues to be unable to pay the Company for subsequent gas deliveries, management estimates that the Company will likely not require additional funding for its ongoing operations before the end of Q3 2015, however the Company would not be able to undertake any significant capital expenditure. There are no guarantees that additional funding will be available if needed, or will be available on suitable terms. Pursuant to its rights under the PGSA, the Company, on 2 April 2014, served a Notice of Dispute to TANESCO demanding payment in full to collect the arrears, as well as examining the Company's legal and contractual options to mitigate a further increase in arrears including but not limited to suspending gas deliveries to TANESCO. The Notice of Dispute has remained in effect whilst the Company sought a mutually acceptable payment plan to clear the arrears within an acceptable time frame. Management is in the process of reviewing all available options to secure regular payments from TANESCO in the light of recent delays in weekly payments subsequent to the quarter end.

The material uncertainties that may cast significant doubt on the Company's ability to continue as a going concern are set forth below. The Company generates on average in excess of 60% of its operating revenue from sales to the Power sector companies, Songas and TANESCO. The financial security of Songas is heavily reliant on the payment of capacity and energy charges by TANESCO, which in turn is dependent on the Government of Tanzania to subsidise a significant portion of TANESCO's operating budget.

At 30 September 2014, TANESCO owed the Company US$54.6 million prior to discount (which includes arrears of US$50.6 million), compared to US$56.6 million (including arrears of US$51.5 million) as at 31 December 2013. During the quarter the Company received a total of US$24.0 million (Q3 2013: US$16.4 million) from TANESCO and, subsequent to the quarter end, TANESCO paid the Company a further US$1.8 million. Receipts for the nine months to 30 September totaled US$45.0 million (2013: US$36.2 million). As of the date of this report, the outstanding balance is US$56.4 million of which US$52.8 million is in arrears.

At the end of Q1 2013, the World Bank approved a Tanzania First Power and Gas Development Policy Operation ("DPO") of US$100 million, the first in a programme of three contemplated operations. The objective of the program is to: (i) strengthen Tanzania's ability to bridge the financial gap in its power sector; (ii) reduce the cost of power supply and promote private sector participation in the power sector; and (iii) strengthen the policy and institutional framework for the management of the country's natural gas resources. TANESCO made tangible progress in late 2013 towards sustainability in securing a 39% power tariff increase from the energy regulator, the Energy Water Utilities Regulatory Authority ("EWURA"). This was an important outcome of the World Bank condition to limit Government subsidies of TANESCO and resulted in the advancement of the Second US$100 million Power and Gas DPO, approved by the World Bank on 26 March 2014 and disbursed at the end of Q2 2014. The Company received approximately US$18.7 million in 2013 from TANESCO around the time of the disbursement of the First DPO. In early July 2014, the Company has received from TANESCO a payment of US$5.96 million against arrears as an allocation of the World Bank Second US$100 million DPO. This was substantially less than that which was represented to the Company prior to disbursement and without an additional significant payment the full Songo Songo drilling programme will not be able to commence.

The DPO programme contemplates a third tranche which the Company understands is conditional, among other things, upon the Tanzania Gas Act being enacted by Parliament.

Management continues to believe that TANESCO will ultimately settle its debts with the Company and has repeatedly requested meetings with TANESCO senior management to agree a payment schedule. However, based on the repayment history as at 30 September 2014, US$9.6 million (Q4 2013: US$9.6 million) of the TANESCO receivable was classified as current and US$45.0 million (Q4 2013: US$47.0 million) before discount was classified as long-term. A discount of US$17.1 million (Q4 2013: US$17.1 million) has been taken against the TANESCO receivable to reflect the estimated cost of delays in collections. The trade receivable was discounted using a risk adjusted discount rate of 15% to reflect the cost of delayed timing of collections from TANESCO. The discount rate and the expected timing of the collections are reviewed at each period end with any adjustments recorded in the period that the estimates change.

As at 30 September 2014, Songas owed the Company US$39.4 million (Q4 2013: US$24.8 million), whilst the Company owed Songas US$27.4 million (Q4 2013: US$16.9 million). There is no contractual right to offset these amounts. Amounts due to Songas primarily relate to pipeline tariff charges of US$25.8 million (Q4 2013: US$15.4 million), whereas the amounts due to the Company are mainly for sales of gas of US$20.6 million (Q4 2013: US$11.6 million) and for the operation of the gas plant for US$18.8 million (Q4 2013: US$13.3 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis without profit margin.

Following an extended period during which no cash was received and no balances set-off, the Company was unable to recognise the Songas receivable. Accordingly, as at 31 March 2014 the Company had fully provided for the net amount due from Songas. However, during the quarter Songas made two payments totalling US$0.8 million in response to cash calls for July and August 2014, and subsequent to the quarter end has made a further three payments totalling US$1.2 million in respect of September, October and November. Management is continuing to work with Songas towards an agreement to set-off outstanding sales, purchases and gas plant operating charges . As a result no additional provision has been made against the net Songas receivable. The existing provision will be released as and when the Company is able to collect the outstanding debt. Any amounts which are not agreed will be pursued by the Company through the dispute mechanisms provided in its agreements with Songas.

SHAREHOLDERS' EQUITY AND OUTSTANDING SHARE DATA

There were 34.9 million shares outstanding as at 30 September 2014 which may be analysed as follows:

	As at	
Number of shares ('000)	**30 Sept 2014**	**31 Dec 2013**
Shares outstanding		
Class A shares	**1,751**	1,751
Class B shares	**33,164**	33,072
Class A and Class B shares outstanding	**34,915**	34,823
Convertible securities		
Options	**400**	1,742
Fully diluted Class A and Class B shares	**35,315**	36,565
Weighted average		
Class A and Class B shares		
Convertible securities	**34,887**	34,719
Options	**16**	–
Weighted average diluted Class A and Class B shares	**34,903**	34,719

As at 20 November 2014, there were a total of 1,750,517 Class A shares and 33,164,415 Class B shares outstanding.

RELATED PARTY TRANSACTIONS

One of the non-executive Directors is a partner at a law firm. During the quarter, the Company incurred US$0.1 million (Q3 2013: US$0.1 million) and for the nine months ended 30 September US$0.2 million (2013: US$0.2 million) to this firm for services provided. The transactions with this related party were made at the exchange amount. The Chief Financial Officer provided services to the Company through a consulting agreement with a personal services company, during the quarter the Company incurred US$0.1 million (Q3 2013 US$ 0.1 million) and for the nine months ended 30 September US$0.3 million (2013: US$0.3 million) to this firm for services provided. As at 30 September 2014 the Company has a total of US$0.1 million (Q3 2013: US$ 0.1 million) recorded in trade and other payables in relation to the related parties.

CONTRACTUAL OBLIGATIONS AND COMMITTED CAPITAL INVESTMENT

CONTRACTUAL OBLIGATIONS

Protected Gas

Under the terms of the original gas agreement for the Songo Songo project ("Gas Agreement"), in the event that there is a shortfall/insufficiency in Protected Gas as a consequence of the sale of Additional Gas, then the Company is liable to pay the difference between the price of Protected Gas (US$0.55/MMbtu escalated) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold (119 Bcf as at 30 September 2014). The Company did not have a shortfall during the reporting period and does not anticipate a shortfall arising during the term of the Protected Gas delivery obligation to July 2024.

The Gas Agreement may be superseded by an initialed Amended and Restated Gas Agreement ("ARGA"). The ARGA provides clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas and the consequences of any insufficiency to a new Insufficiency Agreement ("IA"). The IA specifies terms under which Songas may demand cash security in order to keep it whole in the event of a Protected Gas insufficiency. Should the IA be signed, it will govern the basis for determining security. Under the provisional terms of the IA, when it is calculated that funding is required, the Company is required to fund an escrow account at a rate of US$2.00/MMbtu on all Industrial Additional Gas sales out of its and TPDC's share of revenue, and TANESCO shall contribute the same amount on Additional Gas sales to the Power sector. The funds provide security for Songas in the event of an insufficiency of Protected Gas. The Company is actively monitoring the reservoir and, supported by the report of its independent engineers, does not anticipate that a liability will occur in this respect.

Re-rating Agreement

In 2011, the Company signed a re-rating agreement with TANESCO and Songas (the "Re-Rating Agreement") to increase the gas processing capacity to a maximum of 110 MMcfd (the pipeline and pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-rating Agreement, the Company effectively pays an additional tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA.

Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15 million, but only to the extent that this was not already covered by indemnities from TANESCO or Songas' insurance policies. The Re-rating Agreement expired on 31st December 2012 and in September 2013 was extended by Songas to 31 December 2013. At this time, the Company knows of no reason to de-rate the Songas plant. Since 31 December 2013 production has continued within the higher rated limit and, given the Government's interest in pursuing further development and increasing gas production, the Company expects this to continue. However there are no assurances that this will occur.

Portfolio Gas Supply Agreement

On 17 June 2011, a long term (to June 2023) PGSA was signed between the Company, TPDC and TANESCO. Under the PGSA, the seller is obligated, subject to infrastructure capacity, to sell a maximum of approximately 37 MMcfd for use in any of TANESCO's current power plants, except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately US$2.88/mcf increased to US$2.93/mcf on 1 July 2014. Any volumes of gas delivered under the PGSA in excess of 36 MMcfd are subject to a 150% increase in the basic wellhead gas price.

Operating leases

The Company has two office rental agreements, one in Dar es Salaam, Tanzania and one in Winchester, United Kingdom. The agreement in Dar es Salaam was entered into on 1 November 2013 and expires on 31 October 2015 at an annual rent of US$401 thousand. The agreement in Winchester expires on 25 September 2022 and is at an annual rental of GBP35 thousand (US$58 thousand) per annum during 2012 and 2013 and GBP71 thousand (US$115 thousand) per annum thereafter. The costs of these leases are recognised in the General and Administrative expenses.

Capital Commitments

There are no capital commitments at this time.

CONTINGENCIES

Downstream unbundling

The separation or unbundling of the downstream assets currently in the PSA has been an objective of TPDC and MEM for some time. Unbundling was an issue raised by TPDC in the 2012 GNT negotiations and by MEM in the National Natural Gas Policy issued in 2013, which contemplates TPDC as a 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 methodology for this has been discussed with TPDC in the course of GNT negotiations. During 2013, the Company tabled a proposal with alternative mechanisms to unbundle the downstream from the PSA which were economically neutral to the parties. TPDC did not respond to the proposal and it was later withdrawn by the Company in connection with the termination of negotiations arising from the GNT, and TPDC was advised that the downstream would remain in the PSA until mutually agreed otherwise. The disposition of the downstream business will be addressed at such a time as there is a conflict between new legislation and the Company's rights under the PSA. The results for the nine months reflect the impact of fully recovering downstream costs previously and temporarily excluded from the cost recoverable pool pending resolution of the unbundling of the downstream business and related assets – see note on Cost Pool Adjustments.

TPDC Back-in

TPDC has previously indicated a wish to exercise its right under the PSA to 'back in' to the Songo Songo field development, and a further wish to convert this into a carried interest in the PSA. The current terms of the PSA require TPDC to provide formal notice in a defined period and contribute a proportion of the costs of any development, sharing in the risks in return for an additional share of the gas. To date, TPDC has not contributed any costs. TPDC back-in rights and the potential conversion of these rights into a carried working interest were discussed with the GNT along with other issues, however there were no changes to the PSA agreed between the parties. As such the Company continues to stand behind the original terms of the PSA. Should an amendment to the PSA be agreed in future relating to back-in rights, the impact on reserves and accounting estimates will be assessed at that time and reflected prospectively.

For the purpose of the reserves certification as at 31 December 2013, it was assumed that TPDC will elect to 'back-in' for 20% for all future new drilling activities within the prescribed period as determined by the current development plan, and this is reflected in the Company's net reserve position.

Cost recovery

TPDC conducted an audit of the historic Cost Pool, and in 2011 disputed approximately US$34 million of costs that had been recovered from the Cost Pool from 2002 through to 2009. The Company has contended that the disputed costs were appropriately incurred on the Songo Songo project in accordance with the terms of the PSA. Undertakings to resolve this matter were an outcome of GNT negotiations and the matter was referred to the Controller and Auditor General ("CAG"), head of the National Audit Office of Tanzania. With no progress on resolving the matter, the Company served a Notice of Dispute on TPDC to put the matter to a definitive timeline for resolution, following which the CAG appointed an international independent audit firm to review the disputed costs. The work of the CAG has been completed and TPDC has reviewed the findings. TPDC and Company senior management have held discussions, and are currently in the process of appointing an independent specialist to assist the parties in reaching agreement on costs that are still subject to dispute. The Company has agreed a number of small adjustments, totaling approximately US$1.0 million, and these were removed from the Cost Pool in the second quarter. If the matter is not resolved to the Company's satisfaction, it intends to proceed to arbitration via the International Centre for Settlement of Investment Disputes ("ICSID") pursuant to the terms of the PSA.

TPDC marketing costs

Under the Songo Songo PSA, all reasonable marketing costs, including those incurred by TPDC, with the prior approval by the Company are recoverable. TPDC has to date attempted to claim US$3.6 million in marketing costs from the Company. Management reviewed the claims and can demonstrate that there was no prior approval for such costs, no supporting documentation provided evidencing the expenditure, and further believes the nature of the costs to be unreasonable and not related to marketing the downstream business. Accordingly the Company has rejected the claim by TPDC.

Taxation

During 2013 the Company received a number of assessments for additional tax from the Tanzania Revenue Authority ("TRA"), which together with interest penalties total US$18.4 million. Management, together with tax advisors, have reviewed each of the assessments and believe them to be without merit. The Company has appealed against assessments for additional withholding tax and employment related taxes, and has filed formal objections against TRA's claims for additional corporation tax and VAT.

The Tax Revenue Appeals Board (TRAB) considered the Company's appeal against a withholding tax assessment of US$2.4 million in March 2013 and upheld the assessment. The Company then appealed to Tax Revenue Appeals Tribunal whose decision is awaited. Although a similar appeal to the Tribunal has been decided in favour of TRA, management continues to believe this assessment is flawed and, if necessary, will pursue the case in the Court of Appeal where a similar case is currently being heard.

The Company, based on legal counsel's advice, believes it has strong support, on the basis of tax legislation and the terms of the PSA, for its objection to the additional income tax assessment of US$7.8 million, including penalties. During the quarter TRA notified the Company that it would not accept the objection relating to 2009 and issued a notice confirming the assessment for US$2.5 million. The Company has lodged an appeal against this assessment with the TRAB. In the event that the Company's 2008 and 2010 objections are rejected and subsequent appeals are overturned, any additional tax payable will be recoverable from TPDC under the terms of the PSA.

The Company has filed an objection against a further assessment of VAT, which together with penalties totals US$7.5 million. Again, the Company, based on legal counsel's advice, believes that it has strong grounds for objecting to this assessment and accordingly has made no provision.

The Company has received an assessment of US$0.7 million in respect of employment related taxes which TRA believe to have been underpaid. The Company does not accept TRA's finding and has appealed.

Management continues to review the progress of the above appeals and objections and, as of the date of this report, does not believe any provision is required.

Subsequent to the quarter end TRA conducted an audit of the Company's tax returns for 2011 and issued their audit findings which indicated that additional taxes amounting to US$3.3 million should be paid in respect of employment costs, income and withholding taxes. Management and reviewed the findings which it considers to be without merit and is preparing to respond to TRA. No additional provision is considered necessary at this time.

NEW ACCOUNTING POLICIES

On January 1, 2014 the Company adopted new standards with respect to Employee Contributions (Amendments to IAS 19), Offsetting Financial Assets and Financial Liabilities (Amendments to IAS 32) and Liability for Levies (IFRIC 21). The adoption of these amendments and standards had no impact on the amounts recorded in the consolidated financial statements as at January 1, 2014 or on the comparative periods.

IFRS 9 Financial Instruments (2014) is effective January 1, 2018 with early adoption permitted. IFRS 9 provides guidelines for recognizing and measuring financial assets and liabilities and other contracts to buy or sell non-financial items. The objective is to provide readers with information for the assessment of amounts, timing and probability of the entity's future cash flows. This Standard replaces IAS 39 Financial Instruments: Recognition and Measurement. The Company is currently evaluating the impact that the standard will have on its results of operations and financial position and is assessing when adoption will occur.

IFRS 15 Revenue from Contracts with Customers is effective for fiscal periods ending on or after December 31, 2017 with early adoption permitted. IFRS 15 provides guidelines for reporting information to readers about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The Company intends to adopt IFRS 15 for the annual period beginning on January 1, 2017. The Company is currently evaluating the impact that the standard will have on its results of operations and financial position.

FINANCIAL INSTRUMENT CLASSIFICATION AND MEASUREMENT

The Company classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including expected interest rate, share prices, and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

The Company's long-term trade receivable is considered a Level 3 measurement.

CRITICAL ACCOUNTING POLICES AND ESTIMATES

The preparation of these condensed consolidated interim financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates.

In preparing these condensed consolidated interim financial statements, the significant judgements made by the management in applying the Company's accounting policies and the key sources of estimation uncertainty were the same as those applied to the consolidated financial statements as at and for the year ended 31 December 2013.

SUMMARY QUARTERLY RESULTS

The following is a summary of the results for the Company for the last eight quarters:

US$'000 except where otherwise stated	**2014**			2013				2012
	Q3	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL								
Revenue	**14,852**	19,074	13,698	14,866	14,659	11,996	13,197	20,712
Profit/(loss) after tax	**363**	6,527	1,586	(3,918)	1,928	(6,817)	2,950	5,504
Earnings/(loss) per share - diluted *(US$)*	**0.01**	0.19	0.04	(0.11)	0.05	(0.19)	0.08	0.15
Funds flow from operating activities	**8,288**	13,266	7,104	8,744	11,851	10,546	8,904	12,015
Funds flow per share – diluted *(US$)*	**0.24**	0.37	0.20	0.26	0.34	0.30	0.25	0.33
Operating netback *(US$/mcf)*	**2.22**	3.03	2.03	2.29	2.26	2.10	2.15	3.01
Working capital	**49,618**	37,226	19,060	27,756	31,585	22,527	54,758	46,820
Shareholders' equity	**128,872**	128,528	121,851	120,252	124,170	122,068	128,885	125,935
CAPITAL EXPENDITURES								
Geological and geophysical and well drilling	**292**	–	–	(1,370)	391	103	268	2,160
Pipeline and infrastructure	**–**	(222)	305	397	296	31	–	(258)
Power development	**–**	–	–	–	–	–	–	(15)
Other equipment	**32**	9	178	1,111	57	4	–	562
OPERATING								
Additional Gas sold – Industrial *(MMcf)*	**1,304**	1,046	1,164	1,143	1,092	1,067	1,176	1,127
Additional Gas sold – Power *(MMcf)*	**3,935**	3,503	4,008	4,385	4,959	4,250	4,363	4,417
Average price per mcf – Industrial *(US$)*	**8.85**	9.27	8.11	8.38	8.43	8.60	7.78	8.56
Average price per mcf – Power *(US$)*	**3.60**	3.65	3.52	3.68	4.10	3.63	3.55	3.61