Management's Discussion & Analysis

THIS MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") OF OUR FINANCIAL CONDITION AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES FOR THE YEAR ENDED DECEMBER 31, 2023. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON APRIL 4, 2024. ALL AMOUNTS ARE REPORTED IN US DOLLARS ("$") UNLESS OTHERWISE NOTED.

THIS MD&A CONTAINS NON-GAAP FINANCIAL MEASURES AND RATIOS AND FORWARD-LOOKING INFORMATION. READERS ARE CAUTIONED THAT THIS MD&A SHOULD BE READ IN CONJUNCTION WITH THE DISCLOSURE BELOW UNDER THE HEADINGS "NON-GAAP FINANCIAL MEASURES AND RATIOS", "FORWARD-LOOKING STATEMENTS" AND "GLOSSARY" INCLUDED AT THE END OF THIS MD&A.

Nature of Operations

The principal asset of Orca Energy Group Inc. ("Orca" or the "Company") is its indirect interest in the Songo Songo gas field, as set out in the Production Sharing Agreement ("PSA") between PanAfrican Energy Tanzania Limited ("PAET"), the Tanzanian Petroleum Development Corporation ("TPDC") and the Government of Tanzania ("GoT") in the United Republic of Tanzania. PAET is the Company's wholly owned subsidiary operating in Tanzania. The PSA covers the production and marketing of natural gas from the Songo Songo gas field offshore of Tanzania. The PSA defines the gas produced from the Songo Songo gas field as "Protected Gas" and "Additional Gas". Protected Gas is owned by TPDC and is sold under a 20-year gas agreement (until July 31, 2024) ("Gas Agreement") to Songas Limited ("Songas") and Tanzania Portland Cement PLC ("TPCPLC"). Songas is the owner of the infrastructure that enables the gas to be treated and delivered to Dar es Salaam, which includes a gas processing plant on Songo Songo Island (collectively, the "Songas Infrastructure").

Songas utilizes the Protected Gas as fuel for its gas turbine electricity generators and for onward sale to customers while TPCPLC uses the Protected Gas to fire kilns for the production of cement. A small amount of Protected Gas is also reserved for village electrification. The Company receives no revenue for the Protected Gas delivered to Songas or other recipients of Protected Gas and operates the original wells 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 gas field in excess of the Protected Gas requirements set forth in the PSA (such gas is referred to in this document as "Additional Gas") until the PSA expires in October 2026.

The Tanzanian Electric Supply Company Limited ("TANESCO") is a parastatal organization wholly owned by the GoT with oversight by the Ministry of Energy ("MoE"). TANESCO is responsible for the majority of electricity generation, transmission and distribution throughout Tanzania. Natural gas has become an integral component of TANESCO's power generation fuel mix as a more reliable source of supply over seasonal hydropower as well as a more cost-effective and lower carbon dioxide intensive alternative to liquid fuels. The Company and TPDC as joint sellers currently supply Additional Gas directly to TANESCO by way of the Portfolio Gas Supply Agreement ("PGSA") and indirectly through the supply of Protected Gas and Additional Gas to Songas, which in turn generates and sells power to TANESCO. The Company also supplies Additional Gas to TPDC through a long-term gas sales agreement ("LTGSA") utilizing the National Natural Gas Infrastructure ("NNGI"). The PGSA expires on July 31, 2024 and the LTGSA expires on October 10, 2026. Discussions are now ongoing with TANESCO to extend the PGSA, between the Company, TPDC and TANESCO. TANESCO have confirmed their intent to extend to October 2026 however it is not known at this stage the timing for this.

In addition to supplying gas to TPDC, Songas and TANESCO, the Company has developed 50 contracts to supply gas to Dar es Salaam's industrial market.

Financial and Operating Highlights for the Three Months and Year Ended December 31, 2023

(Expressed in $'000 unless indicated otherwise)	Three Months ended December 31 2023	2022	% Change Q4/23 vs Q4/22	Year ended December 31 2023	2022	% Change Ytd/23 vs Ytd/22
OPERATING						
Daily average gas delivered and sold *(MMcfd)*	**80.8**	95.5	(15)%	**85.6**	86.8	(1)%
Industrial	**13.4**	15.0	(11)%	**13.7**	14.0	(2)%
Power	**67.4**	80.5	(16)%	**71.9**	72.8	(1)%
Average price *($/mcf)*						
Industrial	**8.97**	8.21	9%	**8.73**	8.52	2%
Power	**3.84**	3.60	7%	**3.71**	3.59	3%
Weighted average	**4.69**	4.33	8%	**4.51**	4.38	3%
Operating netback *($/mcf)*[1]	**2.28**	2.42	(6)%	**2.38**	2.62	(9)%
FINANCIAL						
Revenue	**24,448**	31,877	(23)%	**110,235**	118,089	(7)%
Net income/(loss) attributable to shareholders	**(438)**	2,325	(119)%	**7,014**	27,726	(75)%
per share – basic and diluted *($)*	**(0.02)**	0.12	(119)%	**0.35**	1.39	(75)%
Net cash flows from operating activities	**9,858**	15,438	(36)%	**48,485**	67,660	(28)%
per share – basic and diluted *($)*[1]	**0.50**	0.78	(36)%	**2.44**	3.40	(28)%
Capital expenditures[1]	**2,065**	3,615	(43)%	**8,103**	22,406	(64)%
Weighted average Class A and Class B Shares[1] *('000)*	**19,826**	19,893	0%	**19,841**	19,923	0%

	As at December 31, 2023	As at December 31, 2022	% Change
Working capital (including cash)[1]	**67,323**	61,553	9%
Cash and cash equivalents	**101,566**	96,321	5%
Long-term loan	**29,961**	39,762	(25)%
Outstanding shares *('000)*			
Class A	**1,750**	1,750	0%
Class B	**18,051**	18,126	0%
Total shares outstanding	**19,801**	19,876	0%
RESERVES[2,3]			
Gross reserves *(Bcf)*			
Proved	**85**	141	(40)%
Probable	**9**	26	(65)%
Proved plus probable	**94**	167	(44)%
Net present value, discounted at 10% *($ million)*[2,3,4]			
Proved	**108**	147	(27)%
Proved plus probable	**119**	171	(30)%

1 Please refer to the Non-GAAP Financial Measures and Ratios section of the MD&A for additional information.
2 Please refer to the Oil and Gas Advisory section of the MD&A for additional information.
3 Please note that the 2023 numbers reflect the Company's 100% working interest before additional profits tax and government share following the acquisition of Swala (PAEM) Limited's ("Swala UK") 7.933% working interest in 2023. The 2022 numbers reflect the Company's 92.07% working interest before additional profits tax and government share at year end 2022.
4 In accordance with the PSA with the TPDC and the GoT in the United Republic of Tanzania, the Company is able to recover income tax and consequently there is no significant difference between the net present value of reserves on a before and after tax basis. Any capitalized terms otherwise not defined within the Financial and Operating Highlights are defined in the MD&A.

Management's Discussion & Analysis cont.

Financial and Operating Highlights for 2023 and Q4 2023

- Revenue decreased by 23% for Q4 2023 and by 7% for the year ended December 31, 2023 over the comparable prior year periods. The decrease for Q4 2023 over the comparable prior year period is primarily a result of lower sales to the power sector and a lower current income tax adjustment. The decrease for the year ended December 31, 2023 over the comparable prior year period is primarily a result of higher TPDC share of revenue as an outcome of decreased capital expenditures and lower Cost Gas revenue (as defined herein).
- Total gross conventional natural gas production, including fuel gas, was in line with revised forecasts and averaged 121.8 MMcfd for Q4 2023, of which 80.8 MMcfd was Additional Gas. Gas deliveries decreased by 15% for Q4 2023 and by 1% for the year ended December 31, 2023 compared to the same prior year periods. The decrease for Q4 2023 was primarily due to declining production from the currently producing wells and reservoir compartments in the Songo Songo field.
- We currently forecast average Additional Gas sales for 2024 to be in the range of 80-90 MMcfd for the full year, based on current contracted volumes and the end of the Protected Gas regime on July 31, 2024.
- Discussions are ongoing with Songas and TPCPLC to negotiate new gas sales contracts from August 1, 2024 to sell the volumes which are currently supplied as Protected Gas under the Gas Agreement. The obligation to supply Protected Gas ends on July 31, 2024.
- Discussions are also ongoing with TANESCO to extend the PGSA between PAET, TPDC and TANESCO, which currently ends on July 31, 2024.
- Net income attributable to shareholders decreased by 75% for the year ended December 31, 2023 compared to the same prior year period, primarily as a result of the decreased revenue, increased depletion expense, including a one-time accelerated depletion charge in Q4 2023 with respect to costs previously incurred in relation to the 3D seismic acquisition and processing program, and higher net foreign exchange loss.
- Net cash flows from operating activities decreased by 36% for Q4 2023 and by 28% for the year ended December 31, 2023 compared to the same prior year periods, primarily a result of decreased revenue and changes in non-cash working capital.
- Capital expenditures decreased by 43% for Q4 2023 and by 64% for the year ended December 31, 2023 compared to the same prior year period. The capital expenditures in 2023 primarily related to the costs of the planned 2023 well workover program and the 3D seismic acquisition program. The capital expenditures in 2022 primarily related to the 2021-2022 well workover program and the initial costs of the 3D seismic acquisition program.
- The third party contractor responsible for the 3D seismic acquisition program, which was expected to be completed in 2023, suspended its operations. The Company issued a breach of contract notice to the contractor in Q3 2023. The contractor failed to remedy the breach under its agreement with PAET. The Company therefore terminated the contract on October 25, 2023 but remained in discussions with the contractor who is disputing PAET's right to terminate. In Q4 2023, accelerated depletion was recognized on costs incurred to date related to the 3D seismic acquisition. On March 20, 2024 PAET received a summons from the Tanzanian High Court (Commercial Division) to file a written statement of defense against a claim made by the seismic contractor for losses arising from PAET's termination of the contract. The contractor seeks to claim $30.0 million for losses incurred plus legal costs, interest and general damages. The Company in consultation with its legal advisors believes that there are limited merits to the claim and as such does not consider it necessary to include a further provision in the 2023 financial statements. The initial hearing of the claim has been set as April 18, 2024.
- An intervention in the offshore well SS-7 is planned to take place in 2024, subject to the ability to convert Tanzanian shilling balances to US dollars in Tanzania and receipt of the necessary stakeholder approvals. Based on expected supplier mobilization timelines, the earliest start of operations is now in Q2 2024. Following the negotiation of commercial terms with service providers, the total expected project cost has increased to $13.9 million from $8.5 million. The work program is designed to shut off water production which caused the well to die and be shut in from 2019. The cause of the water production is interpreted to be a failed cement bond outside the production liner which created a flow path for water into the well when it was in production. If successful, the SS-7 well is expected to increase field deliverability by 20-25 MMcfd primarily from the currently non-producing southern compartment.
- Front-end engineering continues on the new common inlet manifold in order to optimize gas flow between the Songas gas plant and the NNGI plant, both of which are supplied with gas from the Songo Songo gas field. Project construction and installation is expected to occur in Q4 2024, with commissioning in Q1 2025, subject to final investment decision and stakeholder approvals, at an estimated cost of $5-6 million.
- The production logging program planned in conjunction with the SS-7 intervention will take place in Q2 2024 at an estimated cost of $1.1 million. This work program will provide detailed reservoir information, in addition to the annual pressure surveys, to improve the accuracy of forecasting future reservoir performance. Key targeted wells under the program include wells SS-3, SS-5, SS-7 and SS-10.
- The Company continues to carry out studies to identify opportunities to improve the efficiency of operations at the Songas plant. The Company has installed new positive chokes replacing old units in all wells in Q1 2024 to reduce the pressure drop upstream of the gas processing plant. At a cost of $77,000, this is expected to sustain production during 2024 ahead of the SS-7 intervention.
- Funding of capital projects will be from working capital. All capital allocation decisions will be based upon access to US dollars and prudent economic evaluation to achieve the necessary return given the short time remaining on the PSA, which expires in October 2026.
- During Q2 2023, the Company formally requested TPDC to initiate the process of extending the development license in accordance with the terms of the PSA. The Government Negotiating Committee held a preliminary meeting with the Company in March 2024 to discuss timing around negotiations. The Company continues to seek dialogue with TPDC and the MoE seeking to expedite license extension discussions and will maintain gas sale contract discipline going forward by operating in line with our gas supply agreements.

Financial and Operating Highlights for 2023 and Q4 2023 cont.

- The Company exited the period with $67.3 million in working capital (December 31, 2022: $61.6 million), cash and cash equivalents of $101.6 million (December 31, 2022: $96.3 million) and long-term debt of $30.0 million (December 31, 2022: $39.8 million).
- As at December 31, 2023, the current receivable from TANESCO was $5.9 million (December 31, 2022: $3.7 million). The TANESCO long-term receivable as at December 31, 2023 and as at December 31, 2022 was $22.0 million with a provision of $22.0 million. Subsequent to December 31, 2023 the Company has invoiced TANESCO $8.9 million for 2024 gas deliveries and TANESCO has paid the Company $10.6 million to date.
- On July 21, 2023, the Company repurchased the 7.933% shares in the Company's subsidiary, PAE PanAfrican Energy Corporation ("PAEM"), previously held by Swala UK for $7.5 million and the non-controlling interest was eliminated in Q3 2023.
- On December 17, 2023, the Company, PAEM and PAET entered into a settlement agreement with the Fair Competition Commission ("FCC") of the United Republic of Tanzania to settle allegations under the Provisional Findings issued by the FCC on August 5, 2022. The settlement was made without prejudice to the Company's objections to the validity of the allegations and without any admission of liability, for an aggregate settlement amount of $0.2 million. The payment was made on December 23, 2023.
- Total working interest proved conventional natural gas reserves ("1P") and total proved plus probable conventional natural gas reserves ("2P") decreased by 40% and 44%, respectively, as at December 31, 2023 compared to the prior year. The decrease is due to gross property Additional Gas production in 2023 of 31.3 Bcf (2022: 31.7 Bcf) and declining reservoir pressures, removal of development capital and the number of years remaining on the current term of the Songo Songo license. The reduction in Company gross reserves was partially offset by the 2023 acquisition of a 7.933% interest from Swala UK which increased the Company's working interest share to 100% of the reserves. The net present value of lower reserves and estimated future cash flows from 2P reserves at a 10% discount rate decreased by 30% compared to the previous year. This is mainly the result of the shorter time period remaining to the end of the Songo Songo license.
- Under the terms of the PSA, the Company is required to pay Tanzanian income tax which is fully recovered through the profit-sharing arrangements with TPDC. Income tax has no material impact on the cash flows emanating from the PSA and accordingly there is no significant difference between the net present value of reserves on a before and after tax basis.

Oil and Gas Advisory

The Company's conventional natural gas reserves as at December 31, 2023 disclosed herein were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), independent petroleum engineering consultants, in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

The independent reserves evaluations prepared by McDaniel had an effective date of December 31, 2023 and December 31, 2022 and preparation date of February 1, 2024 and February 24, 2023 respectively. All of the reserves presented herein are conventional natural gas reserves. 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 administrative costs, but after providing for estimated additional profits tax, production costs, development costs, other income and future capital expenditures 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. Such amounts do not represent the fair market value of the Company's reserves. The recovery and reserve estimates of the Company's conventional 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. All of the reserves referenced herein are based on McDaniel's forecast pricing as at December 31, 2023 and December 31, 2022, as applicable.

All the Company's reserves are located in Tanzania. Reserves included herein are stated on a Company gross reserves basis unless noted otherwise. Company gross reserves are the total of the Company's working interest share in reserves and are based on the Company's 100% ownership interest in the reserves (2022: 92.07%). Additional reserves information required under NI 51-101 is included in Orca's reports relating to reserves data and other oil and gas information under NI 51-101, which are filed on its profile on SEDAR+ at www.sedarplus.ca.

Management's Discussion & Analysis cont.

Financial and Operating Highlights for 2023 and Q4 2023 cont.

Oil and Gas Advisory cont.

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

For certainty, all references herein to "production", "gross daily sales", "gas sales" and "Additional Gas sales" are references to conventional natural gas production, conventional natural gas daily sales, conventional natural gas sales and conventional natural gas sales, which are classified as Additional Gas in accordance with the PSA, respectively.

Operating Volumes

The average gross daily sales volume decreased by 15% for Q4 2023 and by 1% for the year ended December 31, 2023 over the comparable prior year periods. The decrease for Q4 2023 was primarily due to declining production from the currently producing wells and reservoir compartments in the Songo Songo field.

The Company's gross sales volumes were split between the industrial and power sectors as detailed in the table below:

	Three Months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Gross sales volume *(MMcf)*				
Industrial sector	**1,230**	1,384	**5,007**	5,098
Power sector	**6,205**	7,402	**26,249**	26,579
Total volumes	**7,435**	8,786	**31,256**	31,677
Gross daily sales volume average *(MMcfd)*				
Industrial sector	**13.4**	15.0	**13.7**	14.0
Power sector	**67.4**	80.5	**71.9**	72.8
Gross daily sales volume average total	**80.8**	95.5	**85.6**	86.8

Industrial Sector

Industrial sector gross daily sales volumes decreased by 11% for Q4 2023 and by 2% for the year ended December 31, 2023 over the comparable prior year periods. The decreases were primarily a result of unscheduled maintenance at a cement plant.

Power Sector

Power sector gross daily sales volumes decreased by 16% for Q4 2023 and by 1% for the year ended December 31, 2023 over the comparable prior year periods. The decreases were primarily a result of decreased gas sales to TANESCO.

Protected Gas Volumes

Protected Gas volumes decreased by 8% to 3,597 MMcf (39.1 MMcfd) for Q4 2023 compared to 3,890 MMcf (42.3 MMcfd) for Q4 2022 and increased by 2% to 14,170 MMcf (38.8 MMcfd) for the year ended December 31, 2023 compared to 13,883 MMcf (38.0 MMcfd) for the year ended December 31, 2022. The Company receives no revenue for Protected Gas volumes; however the volumes are required to calculate total gas produced from the reservoir and the allocation of certain production, distribution and transportation expenses between Protected Gas and Additional Gas.

Commodity Prices

The commodity prices achieved in the different sectors during the year are detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$/mcf	**2023**	2022	**2023**	2022
Average sales price				
Industrial sector	**8.97**	8.21	**8.73**	8.52
Power sector	**3.84**	3.60	**3.71**	3.59
Weighted average price	**4.69**	4.33	**4.51**	4.38

Commodity Prices cont.

Industrial Sector

The average industrial sales price increased by 9% for Q4 2023 and by 2% for the year ended December 31, 2023 over the comparable prior year periods. The increases in prices are primarily due to the underlying increase in the price of Heavy Fuel Oil against which most of the industrial customer contracts are priced.

Power Sector

The average power sector sales price increased by 7% for Q4 2023 and by 3% for the year ended December 31, 2023 compared to the same prior year periods. The average power sector sales price varies depending on whether gas is delivered and sold through the NNGI or the Songas Infrastructure. Sales through the NNGI are to TPDC and do not include processing and transportation tariffs which are included in gas delivered through the Songas Infrastructure.

Revenue

Under the terms of the PSA the Company is responsible for invoicing, collecting and allocating the revenue from Additional Gas sales (see "Principal Terms of the PSA and Related Agreements").

The Company is entitled to recover all costs incurred on the exploration, development and operations of the project ("Cost Gas revenue") up to a maximum of 75% of the net field revenue (gross field revenue less the tariff for processing and pipeline infrastructure) prior to allocating the remaining net field revenue between TPDC and the Company ("Profit Gas revenue"). Any costs not recovered in a period are carried forward for recovery out of future revenues. Once the Cost Gas revenue has been recovered, TPDC is able to recover any pre-approved marketing costs. Currently there are no pre-approved marketing costs for TPDC.

The Company is liable for income tax in Tanzania, but under the terms of the PSA, TPDC's share of revenue is reduced by the current tax payable grossed up at 30% ("income tax adjustment"). Revenue as presented on the Company's Consolidated Statements of Comprehensive Income is calculated by adjusting the Company's operating revenue by the income tax adjustment.

The reconciliation of gross field revenue to Company operating revenue is detailed below:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Industrial sector	**11,028**	11,356	**43,694**	43,437
Power sector	**23,842**	26,659	**97,378**	95,388
Gross field revenue	**34,870**	38,015	**141,072**	138,825
TPDC share of revenue	**(13,318)**	(11,921)	**(47,364)**	(37,841)
Company operating revenue	**21,552**	26,094	**93,708**	100,984
Current income tax adjustment	**2,896**	5,783	**16,527**	17,105
	24,448	31,877	**110,235**	118,089

Revenue decreased by 23% for Q4 2023 and by 7% for the year ended December 31, 2023 over the comparable prior year periods. The decrease for Q4 2023 over the comparable prior year period is primarily a result of lower sales to the power sector and a lower current income tax adjustment. The decrease for the year ended December 31, 2023 over the comparable prior year period is primarily a result of higher TPDC share of revenue as an outcome of decreased capital expenditures and lower Cost Gas revenue, which was partially offset by higher sales to the power sector compared to the year ended December 31, 2022.

The average Additional Gas sales volumes for the quarters and for the years ended December 31, 2023 and December 31, 2022 were above 50 MMcfd which entitled the Company to a 55% share of Profit Gas revenue. The Company was allocated a total of 58% of the Additional Gas net field revenue for Q4 2023 (Q4 2022: 66%) and a total of 63% of the Additional Gas net field revenue for the year ended December 31, 2023 (year ended December 31, 2022: 70%).

Management's Discussion & Analysis cont.

Production, Distribution and Transportation Expenses

The production, distribution and transportation costs are detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Operating costs	**872**	916	**3,941**	3,218
Tariff for processing and pipeline infrastructure	**3,180**	3,270	**12,390**	12,140
Ring-main distribution costs	**524**	613	**2,866**	2,653
	4,576	4,799	**19,197**	18,011

Operating costs include well maintenance costs, PSA license costs, regulatory fees, insurance, certain costs associated with evaluation of the reserves and the costs of personnel not recoverable from Songas. Operating costs are allocated between Protected Gas (recoverable from Songas) and Additional Gas in proportion to their respective volumes during the period. Operating costs decreased by 5% for Q4 2023 and increased by 22% for the year ended December 31, 2023 compared to the same prior year periods. The increase for the year ended December 31, 2023 primarily was a result of increased insurance costs. The amount paid under the tariff for processing and pipeline infrastructure decreased by 3% for Q4 2023 and increased by 2% for the year ended December 31, 2023 compared to the same prior year periods, primarily as a result of fluctuations in gas volumes processed and delivered through the Songas Infrastructure. Ring-main distribution costs decreased by 15% for Q4 2023 and increased by 8% for the year ended December 31, 2023 compared to the same prior year periods. The increase for the year ended December 31, 2023 primarily was a result of higher compressor maintenance costs.

Operating Netback

The operating netback per mcf before general and administrative expenses, tax and Additional Profits Tax ("APT") is detailed in the table below (see "Non-GAAP financial measures and ratios"):

	Three Months ended December 31		Year ended December 31	
$/mcf	**2023**	2022	**2023**	2022
Gas price – Industrial	**8.97**	8.21	**8.73**	8.52
Gas price – Power	**3.84**	3.60	**3.71**	3.59
Weighted average price for gas	**4.69**	4.33	**4.51**	4.38
TPDC Profit Gas entitlement	**(1.79)**	(1.36)	**(1.52)**	(1.19)
Production, distribution and transportation expenses	**(0.62)**	(0.55)	**(0.61)**	(0.57)
Operating netback	**2.28**	2.42	**2.38**	2.62

The operating netback decreased by 6% for Q4 2023 and by 9% for the year ended December 31, 2023 over the comparable prior year periods. The decreases are mainly due to the increase in the TPDC Profit Gas revenue entitlement as an outcome of decreased capital expenditures and lower Cost Gas revenue recoveries by the Company.

General and Administrative Expenses

General and administrative expenses are split between the Company's head office and Tanzania. A significant percentage of general and administration expenses relate to office and management costs that support the Company's operations in Tanzania and are cost recoverable under the PSA.

$'000	Three Months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Tanzania	**2,766**	2,356	**8,601**	8,029
Corporate	**2,768**	1,464	**9,291**	5,519
	5,534	3,820	**17,892**	13,548

General and administrative expenses are detailed in the table below:

$'000	Three Months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Employee and related costs	**2,855**	1,996	**9,988**	7,408
Office costs	**1,295**	913	**4,045**	3,668
ESG, marketing and business development costs	**110**	137	**367**	472
Reporting, regulatory and corporate	**1,274**	774	**3,492**	2,000
	5,534	3,820	**17,892**	13,548

In 2023, the Company approved the long-term retention award plan effective for the period from October 1, 2022 to September 30, 2026 ("Long Term Retention Plan") to encourage retention of its employees, promote employee performance to increase shareholder value over the four-year period, and align the Company's approach to compensation with the Company's strategy to continue and expand its operations in Tanzania upon receipt of a license extension. The total potential award amount payable to eligible participants (employees and directors) under the plan is $4.8 million, with an award payment date of September 30, 2026. This award amount is being recognized on a straight-line basis over the four-year period. Accordingly, as at December 31, 2023, $1.5 million has been recognized as an expense and as an outstanding liability.

General and administrative expenses averaged $1.8 million per month during Q4 2023 (Q4 2022: $1.3 million) and $1.5 million per month for the year ended December 31, 2023 (year ended December 31, 2022: $1.1 million). The 35% increase in employee and related costs for the year ended December 31, 2023 over the comparable prior year period was mainly a result of recruitment of additional corporate employees and the introduction of the Long Term Retention Plan. The 10% increase in office costs for the year ended December 31, 2023 over the comparable prior year period was primarily a result of higher costs related to legal services in Tanzania. The 22% decrease in ESG, marketing and business development costs for the year ended December 31, 2023 over the comparable prior year period was a result of a decrease in business development related costs. The 75% increase in reporting, regulatory and corporate costs for the year ended December 31, 2023 over the comparable prior year period was due to an increase in costs related to professional services, mainly legal services.

Stock Based Compensation

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

$'000	Three Months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Stock appreciation rights ("SARs")	**–**	–	**3**	23
Restricted stock units ("RSUs")	**–**	(1)	**3**	(143)
	–	(1)	**6**	(120)

As at December 31, 2023 there were no SARs or RSUs outstanding (December 31, 2022: 14,000 SARs and 2,833 RSUs). No new SARs or RSUs were issued or forfeited during 2023. 14,000 SARs and 2,833 RSUs were exercised during 2023.

As at December 31, 2023 a total accrued liability of $ nil (December 31, 2022: $0.02 million) has been recognized in relation to SARs and RSUs. In 2023, the Company recognized an expense of $0.006 million for the year (2022: recovery of $0.1 million) on stock based compensation.

Management's Discussion & Analysis cont.

Depletion and Depreciation

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 proved reserves. As at December 31, 2023 the estimated proved reserves remaining to be produced over the term of the PSA as determined by McDaniel in their report dated February 1, 2024 with an effective date of December 31, 2023 and prepared in accordance with NI 51-101 and the COGE Handbook were 85 Bcf (December 31, 2022: 141 Bcf). The average depletion rate was $1.12/mcf for the year ended December 31, 2023 compared to $0.91/mcf for the comparable prior year.

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Oil and natural gas interests	**15,052**	9,886	**41,857**	29,174
Office and other	**35**	25	**120**	70
Right-of-use assets	**53**	69	**252**	284
	15,140	9,980	**42,229**	29,528

The depletion charge for natural gas interests increased by 52% for Q4 2023 and by 43% for the year ended December 31, 2023 over the comparable prior year periods. The increases were mainly due to a reduction in estimated proved reserves. Additionally, during Q4 2023 accelerated depletion totaling $7.0 million was recognized on engineering, acquisition, processing and associated costs related to the 3D seismic acquisition and processing program which will not be pursued in the absence of a license extension.

Finance Income and Expense

Finance income is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Interest income	**748**	300	**1,888**	613
	748	300	**1,888**	613

Finance expense is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Base interest expense	**1,092**	1,276	**4,850**	5,678
Participation interest expense	**702**	1,150	**2,970**	2,936
Lease interest expense	**9**	4	**14**	23
Interest expense	**1,803**	2,430	**7,834**	8,637
Net foreign exchange loss	**526**	157	**5,001**	470
Indirect tax	**298**	331	**1,273**	1,103
Trade and other receivables write off	**830**	–	**830**	–
	3,457	2,918	**14,938**	10,210

Finance Income and Expense cont.

Base interest expense and participation interest expense relate to the long-term loan ("Loan") from the International Finance Corporation ("IFC") to PAET. Base interest on the Loan is payable quarterly in arrears at 10% per annum on a "pay-if-you-can-basis" using a formula to calculate the net cash available for such payments as at any given interest payment date. The participation interest expense is paid annually in arrears. It equates to 6.4% of PAET's net cash flows from operating activities less the net cash flows used in investing activities for the year. Such participation interest will continue to accrue until October 15, 2026 regardless of whether the Loan is repaid prior to its contractual maturity date. The increase in participation interest expense for the year ended December 31, 2023 over the comparable prior year period is primarily a result of the increase in PAET's net cash flows from operating activities, less the net cash used in investing activities.

Net foreign exchange losses are the result of transactions in foreign currencies recorded at the rate of exchange prevailing on the date of such transactions and include both realized and unrealized revaluation gains and losses. Specifically, unrealized revaluation loss represents changes in fair value of cash balances denominated in Tanzanian shillings. Monetary assets and liabilities in foreign currencies are translated at period-end rates. Non-monetary items are translated at historic rates, unless such items are carried at market value, in which case they are translated using the exchange rates that existed when the values were determined. These foreign exchange gains and losses are recorded in finance expense.

The indirect tax includes value added tax ("VAT") on the invoices to TANESCO for interest on late payments. The trade and other receivables write off relates to: (i) VAT on interest invoices to Songas relating to unpaid invoices for the SS-5 and SS-9 workovers; and (ii) an advance which was paid to a supplier and could not be recovered.

Reversal of Loss Allowance

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Reversal of loss allowance	**(4,901)**	(2,528)	**(6,915)**	(10,150)
Loss allowance	**–**	3,240	**–**	3,435
	(4,901)	712	**(6,915)**	(6,715)

The reversal of loss allowance in 2023 follows: (i) the recognition of $4.9 million resulting from agreement with Songas on a revision to the cost sharing in respect of the 2015-2016 workover of the SS-5 and SS-9 wells; and (ii) indirect taxation of $2.0 million relating to the 2020 and 2021 take or pay invoices to TANESCO that were paid in 2023.

The reversal of loss allowance in 2022 follows: (i) collection of TANESCO arrears of $5.6 million which represents the excess of receipts over gas sales invoiced during the year; and (ii) indirect taxation of $4.6 million related to the TANESCO 2017 and 2018 take or pay invoices that were paid in 2022. The loss allowance in 2022 represents: (i) $3.2 million with respect to impairment of Swala Oil & Gas (Tanzania) plc ("Swala TZ") convertible preference shares ("Preference Shares") (see Note 24); and (ii) the net amount of $0.5 million previously allowed for in 2021 with respect to the dispute with the Tanzanian Revenue Authority ("TRA") on the issue of withholding tax on services performed outside Tanzania by non-resident persons in 2010 and 2015-16 and $0.7 million representing the settlement amount with respect to the above withholding tax dispute.

Tax

Income Tax

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Current tax	**3,354**	5,752	**16,133**	15,488
Deferred tax (recovery) expense	**(986)**	(993)	**(6,161)**	1,213
	2,368	4,759	**9,972**	16,701

Under the terms of the PSA with TPDC and the GoT, the Company is liable for income tax in Tanzania at the corporate tax rate of 30%. However, the PSA provides a mechanism by which income tax payable is recovered from TPDC by reducing TPDC's share of Profit Gas revenue and increasing the allocation to the Company. This is reflected in the accounts by increasing the Company's share of revenue by an amount equivalent to current year income taxes payable grossed-up by 30%.

As at December 31, 2023 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 recognized a deferred tax liability of $19.0 million (December 31, 2022: $20.1 million). 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 revenue.

Management's Discussion & Analysis cont.

Tax cont.

Additional Profits Tax

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
APT	**1,753**	2,270	**8,162**	7,613

Under the terms of the PSA, APT is payable when the Company has recovered its costs plus a specified return out of Cost Gas revenue and Profit Gas revenue. As a result: (i) no APT is payable until the Company recovers its costs out of Additional Gas revenue 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 revenue when costs have been recovered with an annual return of 35% plus the percentage change in PPI.

The timing and the effective rate of APT depends on the realized value of Profit Gas revenue which in turn depends on the level of expenditure. The Company provides for APT by annually forecasting the total APT payable in the future as a proportion of the forecast Profit Gas revenue over the term of the PSA. The forecast takes into account the timing of future development capital spending. As at December 31, 2023 the current portion of APT payable was $16.0 million (December 31, 2022: $13.1 million) with a long-term APT payable of $7.5 million (December 31, 2022: $15.3 million). APT of $13.1 million was paid in Q1 2023 based on the 2022 results (Q1 2022: $8.5 million paid based on 2021 results).

The effective APT rate of 11.5% (Q4 2022: 15.6%) has been applied to the Company's share of Profit Gas revenue of $15.3 million for Q4 2023 (Q4 2022: $14.6 million), and average effective rate of 14.5% (2022: 16.8%) has been applied to the Company's share of Profit Gas revenue of $56.2 million for the year ended December 31, 2023 (year ended December 31, 2022: $45.4 million). Accordingly, $1.8 million for the quarter ended December 31, 2023 (Q4 2022: $2.3 million) and $8.2 million for the year ended December 31, 2023 (year ended December 31, 2022: $7.6 million) of APT has been recorded in the Consolidated Statements of Comprehensive Income.

Working Capital

Working capital as at December 31, 2023 was $67.3 million (December 31, 2022: $61.6 million) and is detailed in the table below (also see "Non-GAAP Financial Measures and Ratios"):

	As at December 31			
$'000		**2023**		2022
Cash and cash equivalents		**101,566**		96,321
Trade and other receivables				
Songas	**8,146**		12,640	
TPDC	**3,841**		4,694	
TANESCO	**5,851**		3,736	
Industrial customers and other receivables	**16,176**		15,207	
Loss allowance	**(1,177)**	**32,837**	(1,177)	35,100
Prepayments		**1,637**		1,551
		136,040		132,972
Trade and other liabilities				
TPDC share of Profit Gas revenue[1]	**17,199**		19,440	
Songas	**2,981**		2,933	
Deferred income – take or pay contracts	**1,144**		10,665	
Other trade payables and accrued liabilities	**17,083**		10,154	
Current portion of long-term loan	**10,000**		10,000	
Current portion of APT	**15,984**	**64,391**	13,146	66,338
Tax payable		**4,326**		5,081
		68,717		71,419
Working capital		**67,323**		61,553

1 The balance of $17.2 million payable to TPDC is the liability for TPDC's share of Profit Gas revenue, primarily related to unpaid gas deliveries to TANESCO. The majority of the settlement of this liability is dependent on receipt of payment from TANESCO for arrears. For their allocation of Profit Gas revenue, the Company paid TPDC $5.7 million in February 2023, $11.5 million in April 2023, $4.9 million in July 2023, $11.1 million in October 2023 and $2.4 million in February 2024.

Working Capital cont.

Financial Instruments

Current financial instruments of the Company include cash and cash equivalents, trade and other receivables, trade and other liabilities and tax payable. The carrying values of the financial instruments approximate fair values due to their relatively short periods to maturity. The risks associated with the Company's financial instruments are primarily attributed to the inherent riskiness of the Tanzanian cash holdings and the ability to exchange Tanzanian shillings for hard currencies, and the risk that trade and other receivables may not be paid when due. The Company mitigates these risks by (i) holding, when possible, the majority of its cash (other than Tanzanian shillings) outside of Tanzania in reputable international financial institutions primarily in Jersey and Mauritius which reduces geo-political risk; (ii) monitoring and reviewing the trade and other receivables on a regular basis to determine if allowances are required for overdue amounts or action is required to restrict deliveries on past due accounts to reduce exposure on outstanding receivables; and (iii) seeking payments from its customers, when possible, in US dollars. As of December 31, 2023, over 90% of receipts from domestic customers are denominated in Tanzanian shillings. There are no restrictions on the movement of cash from Jersey, Mauritius or Tanzania.

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets cease to be recognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership.

Working Capital Requirements

The Company expects to have sufficient cash flow from operating activities to maintain adequate working capital to cover both short-term and long-term obligations for 2024, including forecasted debt and interest payments ($14.4 million) and capital expenditure ($21.6 million). The Company has not incurred any material losses from debtors in 2023 and does not expect to incur any losses from debtors in 2024. The Company maintains adequate US dollars and other hard currencies on hand to ensure it can meet all its foreign denominated capital expenditure obligations and deal with possible fluctuations in liquidity from operational problems and US dollar liquidity issues in Tanzania. The Company does not anticipate any circumstances that are reasonably likely to occur that could significantly impact the Company's cash flows and liquidity, however, the global growth slowdown and the impact of the war in Ukraine has seen an increasing decline in foreign exchange reserves in Tanzania, which has given rise to decreased availability in Tanzania of US dollars and other hard currencies and has impaired the Company's ability to convert Tanzanian shillings to US dollars in 2023. There is a risk that the Company may not be able to convert Tanzanian shillings to hard currencies, such as US dollars, in the future as and when required. It is not known when the foreign exchange reserve deficiency in Tanzania will be remedied, if ever.

TANESCO Receivable

As at December 31, 2023 the current receivable from TANESCO was $5.9 million (December 31, 2022: $3.7 million). In 2023 the Company invoiced TANESCO $32.9 million (2022: $29.8 million) for gas deliveries and received $30.8 million (2022: $33.7 million) in payments. These amounts are inclusive of VAT. Based on the consistent payments from TANESCO, the Company: (i) recognized all amounts invoiced for gas deliveries in 2023 and 2022 as revenue; and (ii) recognized $ nil during the year (2022: $5.6 million) as a reversal of loss allowance relating to the amounts collected during the year that were applied towards the long-term TANESCO receivables previously allowed for.

In addition, in 2023 TANESCO paid the Company $13.2 million against the 2020 and 2021 take or pay invoices (2022: $30.0 million paid against the 2017 and 2018 take or pay invoices). $11.2 million of this amount (2022: $25.4 million) was released to the Company's Statements of Comprehensive Income as revenue in 2023. $2.0 million, being the VAT component of the take or pay invoices, was reversed out of loss allowance in 2023 (2022: $4.6 million).

The TANESCO long-term receivable as at December 31, 2023 and as at December 31, 2022 was $22.0 million with a provision of $22.0 million. Subsequent to December 31, 2023 the Company has invoiced TANESCO $8.9 million for 2024 gas deliveries and TANESCO has paid the Company $10.6 million to date.

Management's Discussion & Analysis cont.

Capital Expenditures

The capital expenditures (see "Non-GAAP Financial Measures and Ratios") in 2023 primarily related to the initial costs of the well workover program and the 3D seismic acquisition program. The capital expenditures in 2022 primarily related to the well workover program and the initial costs of the 3D seismic acquisition program.

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Pipelines, well workovers and infrastructure	**2,067**	3,604	**7,984**	22,125
Other capital expenditures	**(2)**	11	**119**	281
	2,065	3,615	**8,103**	22,406

Capital Requirements

Except as described below, there are no contractual commitments for exploration or development drilling or other field development, either in the PSA or otherwise agreed, which would give rise to significant capital expenditure with respect to the Songo Songo gas field. Any additional significant capital expenditure in Tanzania is discretionary.

The third party contractor responsible for the 3D seismic acquisition program, which was originally expected to be completed by the end of 2022 and to cost $24.2 million, suspended its operations in Q3 2023. The Company issued a breach of contract notice to the contractor in Q3 2023. The contractor failed to remedy the breach under its agreement with PAET. The Company therefore terminated the contract on October 25, 2023. In Q4 2023, accelerated depletion was recognized on costs incurred to date related to the 3D seismic acquisition. On March 20, 2024 PAET received a summons from the Tanzanian High Court (Commercial Division) to file a written statement of defense against a claim made by the seismic contractor for losses arising from PAET's termination of the contract. The contractor seeks to claim $30.0 million for losses incurred plus legal costs, interest and general damages. The Company in consultation with its legal advisor believes that there are limited merits to the claim and as such does not consider it necessary to include a further provision in the 2023 financial statements. The initial hearing of the claim has been set as April 18, 2024.

An intervention in the offshore well SS-7 is planned to take place in 2024, subject to the ability to convert Tanzanian shilling balances to US dollars in Tanzania and necessary stakeholder approvals. Based on expected supplier mobilization timelines, earliest start of operations is now in Q2 2024. Following the negotiation of commercial terms with service providers, the total expected project cost has increased to $13.9 million from $8.5 million. The work program is designed to shut off water production which caused the well to be shut in from 2019. The cause of the water production is interpreted to be a failed cement bond outside the production liner which created a flow path for water into the well when it was in production. If successful, the SS-7 well is expected to increase field deliverability by 20-25 MMcfd primarily from the currently non-producing southern compartment.

Front end engineering continues on the new common inlet manifold in order to optimize gas flow across the Songas gas plant and the NNGI plant, both of which are supplied with gas from the Songo Songo gas field. Project construction and installation are expected to occur in Q4 2024, with commissioning in Q1 2025, subject to final investment decision and stakeholder approvals, at an estimated cost of $5-6 million.

The production logging program planned in conjunction with the SS-7 intervention will take place in Q2 2024 at an estimated cost of $1.1 million. This work program will provide detailed reservoir information, in addition to annual pressure surveys, to improve the accuracy of forecasting future reservoir performance. Key targeted wells under the program include wells SS-3, SS-5, SS-7 and SS-10.

The Company continues to carry out studies to identify opportunities to improve the efficiency of operations at the Songas plant. The Company has installed new positive chokes replacing old units in all wells in Q1 2024 to reduce the pressure drop upstream of the gas processing plant. At a cost of $77 thousand, this is expected to sustain production during 2024 ahead of the SS-7 intervention.

With the emergence of longer-term high levels of gas demand, the Company's short-term 2024 forecast capital expenditure remains at approximately $21.6 million.

Long-term Receivables

	As at December 31	
$'000	**2023**	2022
VAT – Songas workovers	**–**	2,205
Lease deposit	**10**	10
	10	2,215

In 2017, based on agreement with TPDC, $12.3 million relating to the Songas share of workover costs of the SS-5 and SS-9 wells was transferred to the cost pool to recover the costs via the PSA cost recovery mechanism. This resulted in $2.2 million relating to VAT on the workovers that had already been paid being reclassified as a long-term receivable. In Q2 2023, Songas agreed to pay the Company $7.6 million as full and final settlement of their share of the workover costs of the SS-5 and SS-9 wells. Pursuant to the agreement with Songas, the originally issued invoices will not be settled, hence the recovery of the associated VAT of $2.2 million has been written off in 2023.

The following table details the amounts receivable from TANESCO that do not yet meet revenue recognition criteria and therefore are not recorded in the consolidated financial statements:

	As at December 31	
$'000	**2023**	2022
Total amounts invoiced to TANESCO	**89,809**	92,547
Trade receivable – TANESCO	**(5,851)**	(3,736)
Unrecognized amounts not meeting revenue recognition criteria[1]	**(61,940)**	(66,793)
Loss allowance	**(22,018)**	(22,018)
	–	–

1 The amount includes invoices for interest on late payments from TANESCO.

Long-term Loan

In 2015 PAET obtained the Loan from the IFC, a member of the World Bank Group, for $60.0 million. The Loan was fully drawn down in 2016.

The Loan is to be paid out through six semi-annual payments of $5.0 million starting October 15, 2022, for which the initial payment was paid by the Company subsequent to October 15, 2022, and one final payment of $25.2 million will be due on October 15, 2025. The Company may voluntarily prepay all or part of the Loan but must simultaneously pay any accrued base interest costs related to the principal amount being prepaid. The Loan is an unsecured subordinated obligation of PAET and was guaranteed by the Company to a maximum of $30.0 million. The guarantee may only be called upon by IFC at maturity in 2025 and, subject to IFC approval and receipt of all required regulatory approvals, the Company, at its discretion, may issue shares in fulfillment of all or part of its guarantee obligation in 2025. Pursuant to the sale of a non-controlling interest in PAEM, the parent company of PAET, in 2018, the Company agreed with the IFC to reduce the outstanding amount of the Loan by the percentage interest sold of 7.933% ($4.8 million) before the fourth anniversary of the first drawdown. PAET made this payment on October 16, 2019.

Dividends and distributions from PAET to PAEM are restricted at any time whenever amounts of interest, principal or participating interest are due and outstanding. All amounts under the Loan have been paid when due.

Management's Discussion & Analysis cont.

Outstanding Shares

The Class A Shares are convertible at any time at the option of the holder into Class B Shares on a one-for-one basis. Subject to the terms and conditions of conversion specified in the memorandum of association and articles of association of the Company, the Class B Shares are convertible into Class A Shares on a one-for-one basis if an offer is made to purchase Class A Shares that: (i) must, by reason of applicable securities legislation or the requirements of a stock exchange on which the Class A Shares are listed, be made to all or substantially all of the holders of Class A Shares; and (ii) are not made concurrently with an offer to purchase Class B Shares that is identical to the offer to purchase Class A Shares and that has no condition attached other than the right not to take up and pay for shares tendered if no shares are purchased pursuant to the offer for Class A Shares. The conversion right does not come into effect under certain events specified in the memorandum of association of the Company, including, without limitation, the prior delivery to the Company's transfer agent and to the Secretary of the Company of a certificate signed by one or more shareholders owning more than 50% of the then outstanding Class A Shares.

Pursuant to the normal course issuer bid commenced on June 21, 2021 ("2021 NCIB"), the Company repurchased and cancelled a total of 60,900 Class B Shares at an average price per Class B Share of CDN$5.18 as of June 30, 2022. Pursuant to the normal course issuer bid commenced on July 11, 2022 ("2022 NCIB"), the Company had repurchased and cancelled a total of 81,000 Class B Shares at a weighted average price of CDN$4.89 as of December 31, 2023.

On November 1, 2023 the Company announced the 2023 NCIB to commence on November 6, 2023 to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. As at December 31, 2023 the Company has repurchased for cancellation 40,900 Class B Shares at a weighted average price of CDN$4.59 pursuant to the 2023 NCIB. As at April 4, 2024 the Company had repurchased 40,900 Class B Shares at a weighted average price of CDN$ 4.59 pursuant to the 2023 NCIB. 1,749,895 Class A Shares and 18,051,414 Class B Shares were outstanding as at December 31, 2023; 1,749,895 Class A Shares and 18,051,414 Class B Shares were outstanding as at April 4, 2024. See "Substantial Issuer Bid, Normal Course Issuer Bid and Dividends" in this MD&A.

Cash Flow Summary

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Operating activities				
Net (loss)/income	**(438)**	3,014	**7,014**	30,280
Non-cash adjustments	**16,194**	15,018	**48,619**	42,342
Interest expense	**1,803**	2,430	**7,834**	8,637
Changes in non-cash working capital[1]	**(7,701)**	(5,024)	**(14,982)**	(13,599)
Net cash flows from operating activities	**9,858**	15,438	**48,485**	67,660
Net cash used in investing activities	**(2,209)**	(4,082)	**(8,794)**	(25,731)
Net cash used in financing activities	**(7,905)**	(8,136)	**(31,738)**	(18,690)
(Decrease) increase in cash	**(256)**	3,220	**7,953**	23,239

1 See Consolidated Statements of Cash Flows.

Net income decreased by 77% for the year ended December 31, 2023 over the comparable prior year period, primarily as a result of the decreased revenue, increased depletion expense, including a one-time accelerated depletion charge in Q4 2023 with respect to costs previously incurred in relation to the 3D seismic acquisition and processing program, and higher net foreign exchange loss. The Company's net cash flows from operating activities decreased by 36% for Q4 2023 and by 28% for the year ended December 31, 2023 over the comparable prior year periods, primarily as a result of decreased revenue. In addition, the decrease of the Company's net cash flows from operating activities for the year ended December 31, 2023 over the comparable prior year period was a result of a reversal of $5.6 million loss allowance relating to the amounts collected from TANESCO during Q3 2022. The decrease in net cash used in investing activities for Q4 2023 and for the year ended December 31, 2023 over the comparable prior year periods were mainly a result of higher expenditure in 2022 in relation to the well workover program. The increase in net cash used in financing activities for the year ended December 31, 2023 over the comparable prior year period was mainly an outcome of the purchase of the non-controlling interest shareholding in Q3 2023.

Related Party Transactions

The Chair of the Company's Board of Directors is a partner of Burnet, Duckworth & Palmer LLP, a law firm that provides legal advice to the Company and its subsidiaries. Fees for services provided by this firm totaled $0.3 million for the quarter ended December 31, 2023 (Q4 2022: $0.1 million) and $0.8 million for the year ended December 31, 2023 (year ended December 31, 2022: $0.5 million).

As at December 31, 2023, the Company had a total of $0.6 million (December 31, 2022: $0.1 million) recorded in trade and other liabilities in relation to related parties.

Normal Course Issuer Bid and Dividends

On June 21, 2021, the Company commenced the 2021 NCIB to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. Purchases pursuant to the 2021 NCIB were made by Research Capital Corporation ("Research Capital") on behalf of the Company and were not to exceed 500,000 Class B Shares, representing approximately 2.74% of the total outstanding Class B Shares. The 2021 NCIB was in effect until June 21, 2022. An aggregate of 60,900 Class B Shares were repurchased by the Company pursuant to the 2021 NCIB at an average price per Class B Share of CDN$5.18.

On July 5, 2022 the Company announced the 2022 NCIB to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. Purchases pursuant to the 2022 NCIB were made by Research Capital on behalf of the Company and were not to exceed 500,000 Class B Shares, representing approximately 2.75% of the total outstanding Class B Shares as of July 4, 2022. The 2022 NCIB was in effect from July 11, 2022 until July 11, 2023. An aggregate of 81,000 Class B Shares were repurchased and cancelled by the Company pursuant to the 2022 NCIB at a weighted average price per Class B Shares of CDN$4.89.

On November 1, 2023 the Company announced the 2023 NCIB to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. Purchases pursuant to the 2023 NCIB will be made by Research Capital on behalf of the Company and will not exceed 500,000 Class B Shares, representing approximately 2.76% of the total outstanding Class B Shares as of October 31, 2023. The 2023 NCIB will be in effect from November 6, 2023 until November 5, 2024 (or until such time as the maximum number of Class B Shares have been purchased). Purchases of Class B Shares will be made by Research Capital based on the parameters prescribed by the TSXV and applicable securities laws. The acquisition price of Class B Shares under the 2023 NCIB will not exceed the market price of the Class B Shares at the time of acquisition and the funds available to acquire the Class B Shares will come from the Company's working capital and cash flow. All Class B Shares purchased under the 2023 NCIB will be cancelled. As at April 4, 2024, the Company has repurchased for cancellation 40,900 Class B Shares at a weighted average price of CDN$ 4.59 pursuant to the 2023 NCIB.

Shareholders may obtain a copy of the notice regarding the 2021 NCIB, 2022 NCIB and 2023 NCIB filed with the TSXV from the Company without charge.

Dividend Summary

Declaration date	Record date	Payment date	Amount per share (CDN$)
February 1, 2024	March 29, 2024	April 12, 2024	0.10
November 15, 2023	December 29, 2023	January 12, 2024	0.10
August 16, 2023	September 29, 2023	October 13, 2023	0.10
May 17, 2023	June 30, 2023	July 14, 2023	0.10
February 24, 2023	March 31, 2023	April 14, 2023	0.10

Consolidation

The companies which are being consolidated for the purposes of this MD&A are:

Subsidiary	Incorporated	Holding
Orca Energy Group Inc.	British Virgin Islands	Parent Company
Orca Exploration UK Services Limited	United Kingdom	100%
PAE PanAfrican Energy Corporation	Mauritius	100%
PanAfrican Energy Tanzania Limited	Jersey	100%

Management's Discussion & Analysis cont.

Non-Controlling Interest

The Company sold 7.933% (7,933 Class A common shares) of PAEM to a wholly owned subsidiary of Swala TZ, Swala UK, in 2018 for $15.4 million cash and $4.0 million of Swala TZ's Preference Shares pursuant to a share purchase agreement. The Preference Shares entitled the Company to a 10% per annum distribution payable 15 days after each quarter end commencing from the closing date, January 16, 2018. Payment of the quarterly distributions was at the discretion of Swala TZ based on funds available, however, the liability accrued if any amount was unpaid when due. For any distributable amount remaining unpaid at December 31, 2021, the Company may demand settlement and Swala TZ was obligated to comply by transferring and returning the Class A common shares of PAEM sold to Swala TZ. The aggregate value of these shares will equal the amount of the outstanding distributions.

Swala TZ was obligated to redeem 20% of the Preference Shares for cash annually starting from December 31, 2021 until all shares are redeemed. If at any time Swala TZ did not redeem in cash the required number of Preference Shares, Swala TZ was obligated to redeem the Preference Shares by transferring and returning the Class A common shares of PAEM sold to Swala TZ. The aggregate value of these Class A common shares is equal to the amount of any outstanding redemption. On August 8, 2022, the Company issued a redemption notice to Swala TZ, requesting that Swala TZ redeem 20% of the outstanding Preference Shares by August 23, 2022. On January 31, 2023 the Company issued a further redemption notice to Swala TZ, requesting that Swala TZ redeem a further 20% of the outstanding Preference Shares by February 15, 2023.

On April 3, 2023, Swala TZ announced that its creditors resolved that be placed into liquidation at a creditors' meeting held on March 31, 2023. On March 31, 2023, Apex Corporate Trustees (UK) Limited appointed representatives of Grant Thornton UK LLP as administrators of Swala UK. On July 21, 2023, the Company repurchased the 7.933% shares in PAEM held by Swala UK for $7.5 million and the non-controlling interest is therefore eliminated in 2023.

A reconciliation of the non-controlling interest is detailed below:

	As at December 31	
$'000	**2023**	2022
Balance, beginning of year	**5,670**	3,116
Net income attributable to non-controlling interest	**–**	2,554
Distribution to non-controlling interest shareholder	**(7,500)**	–
Elimination of non-controlling interest	**1,830**	–
Balance, end of year	**–**	5,670

Contingencies

Taxation

Amounts in $'millions					As at December 31 2023	2022
Area	Period	Reason for dispute	Principal	Interest and penalties	Total	Total
Income tax	2008-09, 2011-20	Deductibility of capital expenditures and expenses (2012, 2015 and 2016), additional income tax (2008, 2011 and 2012), foreign exchange rate application (2013 to 2015, 2018 to 2020), underestimation of tax due (2014, 2016 and 2020) and methodology of grossing up income taxes paid (2015 to 2017).	**20.8**	**13.3**	**34.1**[1]	34.2
Tax on repatriated income	2012-21	Applicability of withholding tax on repatriated income (2012 to 2021)	**20.4**	**4.0**	**24.4**[2]	24.9
VAT	2012-20	VAT already paid (2012 to 2014), VAT on imported services (2015 and 2016), interest on VAT decreasing adjustments (2017) and input VAT on services (2017 to 2020).	**0.2**	**1.3**	**1.5**[3]	1.6
			41.4	**18.6**	**60.0**	60.7

During 2022, following the expiry of the statutory deadline for the TRA to respond to the Company's objections, the Company filed notices of intention to appeal to the Tanzania Revenue Appeals Board ("TRAB") against the corporate income tax assessments for the years of 2012 to 2016, tax on repatriated income for the years of 2012 to 2014, and VAT for the years of 2015 to 2016. On several occasions during 2022 these matters came for hearing, and in April 2023, the Company received determination letters from the TRA. Further to that, in May 2023, the TRA issued final corporate income tax assessments for the years of 2012 to 2016, in which the TRA agreed to drop certain claims with respect to previously assessed corporate income tax for the years of income of 2012 and 2016. These claims are no longer represented in the table above.

On May 15, 2023, the Company filed statements of appeal at the TRAB for the remainder of claims on TRA's notice of assessments with respect to the corporate income tax assessments for the years of 2012 to 2016 and tax on repatriated income for the years of 2012 to 2014. The TRAB adjourned the hearings of appeals and the date of hearing is now on notice. The TRAB further received written submissions from both parties on the preliminary objection raised by the TRA against the Company's repatriated income tax appeals for the years of 2012 to 2014 and the parties are awaiting TRAB's decision.

On May 22, 2023, the TRAB pronounced its judgment on the VAT appeal for the years of 2015 and 2016 ($0.2 million) in favor of the Company. A written judgment is still pending. The TRA did not file a Notice of Intention to Appeal at Tax Revenue Appeals Tribunal ("TRAT") by the statutory filing deadline. The Company continues to monitor actions taken by the TRA.

In Q4 2022, the TRA issued seven assessments for tax on repatriated income ($10.6 million) for the years of 2015 to 2021. The Company objected to the assessments on the grounds of the assessments lacking merit; additionally, the assessments for the years of 2015 and 2016 were time-barred. In Q1 2023, the Company received TRA's proposals to settle the objections. In Q2 2023, the Company responded to the proposals. In Q3 2023, following TRA's failure to issue final determination on the objections within the statutory time limit, the Company filed Notices of Intention at Appeal at the TRAB and later filed statements of appeal and is awaiting a hearing date.

In Q4 2022, the TRA issued six assessments for income tax and for ensuing interest on deemed delayed payments ($0.5 million) for the years of 2018 to 2020. The Company objected to the assessments on the grounds of incorrect disallowance of expenses and use of exchange rates. In Q1 2023, the Company received TRA's proposals to settle the objections. In Q2 2023, the Company responded to the proposals. In Q3 2023, following TRA's failure to issue a final determination on the objections within the statutory time limit, the Company filed Notices of Intention at Appeal at the TRAB. In Q4 2023, the Company filed statements of appeal. On March 1, 2024 and March 19, 2024, the appeals came for hearing at the TRAB. Parties are expected to file closing submissions by April 9, 2024.

In Q3 2023, the TRAT pronounced its judgement on the corporate income tax appeal for the year 2011 ($1.6 million) in favour of the TRA. The Company filed a Notice of Intention to Appeal at the Court of Appeal of Tanzania ("CAT"). In Q4 2023, the Company filed a Memorandum of Appeal and is awaiting a hearing date. In Q4 2023, the Company recorded a provision of approximately $0.3 million.

In Q4 2022, the TRA issued an assessment for VAT ($0.1 million) for the years of 2019 and 2020. The Company objected to the assessment on the grounds that TRA incorrectly disallowed input VAT on certain services. In Q1 2023, the Company received TRA's proposals to settle the objections. In Q2 2023, the Company responded to the proposals. In Q3 2023, following TRA's failure to issue final determination on the objections within the statutory time limit, the Company filed Notices of Intention at Appeal at the TRAB. In Q4 2023, the Company filed statements of appeal. On March 18, 2024 the Company filed its written submissions and the TRA is expected to file its reply by April 1, 2024.

Management's Discussion & Analysis cont.

Contingencies cont.

Taxation cont.

Management, with advice from its legal counsel, has reviewed the Company's position on the objections and appeals related to the disputed amounts and has concluded that no further provision is required. However, if the TRA reassesses the Company's tax returns for open taxation years on a similar basis, the Company may be required to make future deposits to object such assessments.

The process of appealing assessments issued by the TRA starts by initially filing an appeal with the TRA. If this is not successful, claims can be taken to higher authorities starting with the TRAB, followed by an appeal to the TRAT and finally to the CAT. Below is a summary of the status of the various assessments:

(1) (a) 2008 ($0.6 million): The Company objected to the TRA assessment that did not recognize a tax loss carried forward and is awaiting a response;
(b) 2009 ($0.7 million): The Company objected to an amended assessment from the TRA for being time-barred and arbitrary and is awaiting a TRA response;
(c) 2011 ($1.6 million): The Company is awaiting a CAT hearing date following the TRAT ruling in favor of the TRA;
(d) 2012 ($9.2 million): The Company appealed to the TRAB objecting to the TRA assessment with respect to understated revenue and deductibility of capital expenditures and expenses;
(e) 2013 ($1.9 million): The Company appealed to the TRAB objecting to the TRA assessment as being time-barred and without merit;
(f) 2014 ($4.9 million): The Company appealed to the TRAB objecting to the TRA assessment on the grounds that the TRA assessment incorrectly disallowed certain expenses and applied erroneous foreign exchange rates;
(g) 2015-16 ($8.1 million): The Company appealed to the TRAB as to TRA's assessments on the grounds that the TRA assessments failed to recognize provisional tax payments, incorrectly disallowed capital expenditures and certain expenses and applied erroneous foreign exchange rates;
(h) 2017 ($6.6 million): The TRA issued an assessment for corporation tax which questioned the Company's methodology of grossing up already paid corporation tax ($6.5 million) and raised the issue of imposing interest on deemed delayed payment ($0.1 million). The Company filed an objection and is awaiting the TRA's response;
(i) 2018 ($0.02 million): The Company appealed to the TRAB objecting to the TRA's assessment on the grounds that the TRA incorrectly disallowed certain expenses and applied erroneous foreign exchange rates;
(j) 2018-20 ($0.5 million): The Company appealed to the TRAB objecting to the TRA assessment on the grounds that the TRA incorrectly disallowed certain expenses and failed to recognise payments already made;

(2) (a) 2012 ($2.9 million): The Company objected to the TRA assessment as being without merit and, following expiry of the statutory deadline for the TRA to respond, filed an appeal at the TRAB and is awaiting TRAB's decision;
(b) 2013 ($7.5 million): The Company objected to the TRA assessment as being time-barred and without merit and, following expiry of the statutory deadline for the TRA to respond, filed an appeal at the TRAB and is awaiting TRAB's decision;
(c) 2014 ($3.4 million): The Company objected to the TRA assessment as being without merit and, following expiry of the statutory deadline for the TRA to respond, filed an appeal at the TRAB and is awaiting TRAB's decision;
(e) 2015-21 ($10.6 million): The Company appealed to the TRAB objecting to the TRA assessments for the year of income of 2015 ($1.9 million), 2016 ($1.9 million), 2017 ($1.6 million), 2018 ($1.1 million), 2019 ($1.6 million), 2020 ($1.1 million) and 2021 ($1.4 million) for being without merit and is awaiting hearing dates;

(3) (a) 2012-16 ($0.2 million): The TRAB ruled in favor of the Company, parties are awaiting the written judgment. The TRA has not appealed the decision to the TRAT;
(b) 2017-18 ($1.2 million): The Company filed an objection to a TRA assessment and is awaiting a response. The Company objected to incorrect imposition of interest on VAT decreasing adjustments in respect of delayed TANESCO payment ($1.2 million) and disallowing input VAT claimed in certain services ($0.1 million);
(c) 2019-20 ($0.1 million): The Company appealed to the TRAB objecting to a TRA assessment on the grounds of incorrectly disallowing input VAT claimed.

In 2016 the TRA introduced significant changes in relation to the income tax treatment of the extractive sector with separate new chapters in Part V of the Income Tax Act 2004 ("ITA, 2004") for mining and for petroleum to be effective commencing in 2018. Further changes were subsequently made by the Written Laws (Miscellaneous Amendments) Act, 2017 ("WLMAA, 2017") and in particular section 36(a)(ii) of the WLMAA, 2017. The WLMAA, 2017 amended sections 65M and 65N of the ITA, 2004 to exclude cost oil/cost gas from inclusion in both income and expenditure. The Company continues to review the tax effects of the changes as there are a number of uncertainties and ambiguities as to the interpretation and application of certain provisions of the WLMAA, 2017. In the absence of guidance on these matters, the Company has used what it believes are reasonable interpretations and assumptions in applying the WLMAA, 2017 for purposes of determining its tax liabilities and the results of operations, which may change as it receives additional clarification and implementation guidance. The Company does not expect a significant impact from the changes as it is able to recover taxes payable from the TPDC Profit Gas revenue entitlement under the terms of the PSA.

Accounting Changes

The following pronouncements from the International Accounting Standards Board ("IASB") became effective or were amended for financial reporting periods beginning on or after January 1, 2023. There has been no impact on the Company.

- IFRS 17 Insurance Contracts
- Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)
- Definition of Accounting Estimate (Amendments to IAS 8)
- Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction (Amendments to IAS 12)
- International Tax Reform – Pillar Two Model Rules (Amendments to IAS 12).

The following standards have been issued but are not yet effective:

- Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current (Amendments to IAS 1)
- Lease Liability in a Sale and Leaseback (Amendments to IFRS 16)
- Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)
- IFRS S1 General Requirements for Disclosure of Sustainability-related Financial Information and IFRS S2 Climate-related Disclosures
- Lack of Exchangeability (Amendments to IAS 21).

The Company intends to adopt these standards when they become effective and is currently evaluating the potential impact.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") for Orca. DC&P, as defined in National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities law and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. The CEO and CFO of Orca evaluated the effectiveness of the design and operation of the Company's DC&P. Based on the evaluation, the officers concluded that Orca's DC&P were effective as at December 31, 2023.

Quarterly Results Summary

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

Figures in $'000	2023				2022			
except where otherwise stated	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**24,448**	27,374	28,006	30,407	31,877	30,537	28,223	27,452
Net (loss)/income attributable to shareholders	**(438)**	256	3,282	3,914	2,325	11,443	6,567	7,391
Earnings/(loss) per share								
– basic and diluted ($)	**(0.02)**	0.01	0.17	0.19	0.12	0.57	0.33	0.37
Net cash flows from operating activities	**9,858**	14,995	16,160	7,472	15,438	19,544	28,601	4,077
Capital expenditures	**2,065**	2,928	1,405	1,705	3,615	1,222	3,306	14,263

Revenue increased in Q2 2022 as a result of increased sales to the power sector. Revenue increased in Q3 2022 as a result of increased sales to the power sector and a higher current income tax adjustment. Revenue increased in Q4 2022 as a result of a further increase in sales to both the industrial sector and the power sector and a higher current income tax adjustment. Revenue decreased in Q1 2023 as a result of a decrease in sales to the industrial sector. Revenue decreased in Q2 2023 as a result of a further decrease in sales to both the industrial sector and the power sector partially offset by a decreased TPDC share of revenue. Revenue decreased in Q3 2023 as a result of an increased TPDC share of revenue. Revenue decreased in Q4 2023 as a result of a decrease in sales to the industrial sector, an increase in TPDC share of revenue and a lower current income tax adjustment.

Management's Discussion & Analysis cont.

Quarterly Results Summary cont.

Net income attributable to shareholders was affected by several factors, other than changes in revenue, including:

- the decrease in Q2 2022 was a result of an increase in finance expense;
- the increase in Q3 2022 was a result of a collection of TANESCO arrears;
- the decrease in Q4 2022 was a result of no collection of TANESCO arrears compared to Q3 2022 and the impairment of the investment in Swala TZ in Q4 2022;
- the increase in Q1 2023 was a result of a higher deferred tax recovery;
- the decrease in Q2 2023 was a result of higher general and administrative and finance expenses;
- the decrease in Q3 2023 was a result of lower reversal of loss allowance for receivables, an expense in relation to the Long Term Retention Plan and a higher foreign exchange loss; and
- the increase in Q4 2023 was a result of higher foreign exchange in the previous quarter, partially offset by a higher depletion expense.

In addition to the factors impacting net income attributable to shareholders, net cash flows from operating activities were primarily affected by the timing and amount of payments received from TANESCO. The increase in Q2 2022 was a result of the payment of the current APT liability in the previous quarter and changes in non-cash working capital. The decrease in Q3 2022 was primarily a result of the changes in non-cash working capital, namely the decrease in accounts payable related to deferred income on take or pay contracts. The decreases in Q4 2022 and Q1 2023 were primarily a result of the changes in the non-cash working capital, namely the decreases in tax payable and trade and other payables. Similarly, the increase in Q2 2023 was primarily a result of the changes in the non-cash working capital, namely the decrease in trade and other receivables. The decrease in Q3 2023 was primarily a result of the changes in the non-cash working capital, namely the decrease in trade and other payables. The decrease in Q4 2023 was primarily a result of the changes in the non-cash working capital, namely the increase in trade and other receivables.

Capital expenditures in Q1 and Q2 2022 were mainly related to the well workover program. Capital expenditures in Q3 2022 were mainly related to the well workover program and the 3D seismic acquisition program. Capital expenditures in Q4 2022 and Q1, Q2 and Q3 2023 were mainly related to the 3D seismic acquisition program. Capital expenditures in Q4 2023 were mainly related to well planning activities.

Selected Annual Financial Information

Selected annual financial information derived from the audited consolidated financial statements for the years ended December 31, 2023, 2022 and 2021 is set out below:

Figures in $'000 except per share amount	**2023**	2022	2021
Revenue	**110,235**	118,089	86,022
Net income attributable to shareholders	**7,014**	27,726	16,370
Earnings – basic and diluted ($ per share)	**0.35**	1.39	0.81
Cash dividends declared (CDN$ per Class A and B Shares)	**0.40**	0.40	0.40
Net cash flows from operating activities	**48,485**	67,660	40,110
Total non-current liabilities	**58,036**	81,378	95,744
Total assets	**215,431**	248,083	230,271

The 37% increase of revenue in 2022 compared to 2021 was primarily a result of increased sales to the power sector partially offset by a higher TPDC share of revenue as a result of increased gross field revenue. The 7% decrease of revenue in 2023 compared to 2022 was primarily a result of higher TPDC share of revenue as an outcome of decreased capital expenditures and lower Cost Gas revenue. This was partially offset by higher sales to the power sector.

The increase in net income attributable to shareholders in 2022 was a result of higher revenue and increased reversal of loss allowances related to the collection of TANESCO arrears. The decrease in net income attributable to shareholders in 2023 was a result of the decreased revenue, increased depletion expense and higher net foreign exchange loss.

In 2023, 2022 and 2021, the Company approved quarterly dividends, CDN$0.10 per share for Q1, Q2, Q3 and Q4. Please refer to the table in the Normal Course Issuer Bid and Dividends section of this MD&A.

The changes in net cash flows from operating activities are primarily related to the changes in non-cash working capital primarily associated with variations in prepayments, trade and other receivables and trade and other liabilities.

The $14.4 million decrease in total non-current liabilities in 2022 compared to 2021 and the $23.3 million decrease in total non-current liabilities in 2023 compared to 2022 were primarily a result of the payment of a portion of the APT and the repayment of the Loan.

Total assets increased by 8% in 2022 compared to 2021. The increase was primarily a result of increases in cash and cash equivalents and trade and other receivables. Total assets decreased by 13% in 2023 compared to 2022 mainly as a result of depletion of capital assets including one time accelerated depletion of costs related to the 3D seismic acquisition and processing program.

Non-GAAP Financial Measures and Ratios

In this MD&A, the Company has disclosed the following non-GAAP financial measures, non-GAAP ratios and supplementary financial measures: capital expenditures, operating netback, operating netback per mcf, working capital, net cash flows from operating activities per share and weighted average Class A and Class B Shares.

These non-GAAP financial measures and ratios disclosed in this MD&A do not have any standardized meaning under International Financial Reporting Standards ("IFRS") and may not be comparable to similar financial measures disclosed by other issuers. These non-GAAP financial measures and ratios should not, therefore, be considered in isolation or as a substitute for, or superior to, measures and ratios of Company's financial performance defined or determined in accordance with IFRS. These non-GAAP financial measures and ratios are calculated on a consistent basis from period to period.

Non-GAAP Financial Measures

Capital Expenditures

Capital expenditures is a useful measure as it provides an indication of our investment activities. The most directly comparable financial measure is net cash from (used in) investing activities. A reconciliation to the most directly comparable financial measure is as follows:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Pipelines, well workovers and infrastructure	**2,067**	3,604	**7,984**	22,125
Other capital expenditures	**(2)**	11	**119**	281
Capital expenditures	**2,065**	3,615	**8,103**	22,406
Right of use	**852**	–	**852**	51
Change in non-cash working capital	**(708)**	467	**(161)**	3,274
Net cash used by investing activities	**2,209**	4,082	**8,794**	25,731

Operating Netback

Operating netback is calculated as revenue less processing and transportation tariffs, TPDC's revenue share, and operating and distribution costs. The operating netback summarizes all costs that are associated with bringing the gas from the Songo Songo gas field to the market, and is a measure of profitability. A reconciliation to the most directly comparable financial measure is as follows:

	Three Months ended December 31		Year ended December 31	
$'000	**2023**	2022	**2023**	2022
Revenue	**24,448**	31,877	**110,235**	118,089
Production, distribution and transportation expenses	**(4,576)**	(4,799)	**(19,197)**	(18,011)
Net production revenue	**19,872**	27,078	**91,038**	100,078
Less current income tax adjustment (recorded in revenue)	**(2,896)**	(5,783)	**(16,527)**	(17,105)
Operating netback	**16,976**	21,295	**74,511**	82,973
Sales volumes MMcf	**7,435**	8,786	**31,256**	31,677
Netback $/mcf	**2.28**	2.42	**2.38**	2.62

Non-GAAP Ratios

Operating Netback per mcf

Operating netback per mcf represents the profit margin associated with the production and sale of Additional Gas and is calculated by taking the operating netback and dividing it by the volume of Additional Gas delivered and sold. This is a key measure as it demonstrates the profit generated from each unit of production.

Management's Discussion & Analysis cont.

Supplementary Financial Measures

Working Capital

Working capital is defined as current assets less current liabilities, as reported in the Company's Consolidated Statements of Financial Position. It is an important measure as it indicated the Company's ability to meet its financial obligations as they fall due.

Net Cash Flows from Operating Activities per Share

Net cash flows from operating activities per share is calculated as net cash flows from operating activities divided by the weighted average number of shares, similar to the calculation of earnings per share. Net cash flow from operations is an important measure as it indicates the cash generated from the operations that is available to fund ongoing capital commitments.

Weighted Average Class A and Class B Shares

In calculating the weighted average number of shares outstanding during any period, the Company takes the opening balance multiplied by the number of days until the balance changes. It then takes the new balance and multiplies that by the number of days until the next change, or until the period end. The resulting multiples of shares and days are then aggregated and the total is divided by the total number of days in the period.

Use of Estimates and Judgments

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. The reader is referred to Orca's December 31, 2023 audited consolidated financial statements for a description of estimates and judgments.

Business Risks

Industry and Business Conditions

Competition and Operational Risk

The natural gas industry is intensely competitive and the Company competes with other companies which possess greater technical and financial resources. Natural gas drilling and production operations are subject to all the risks typically associated with such operations, including but not limited to risks of fires, blowouts, spills, cratering and explosions, mechanical and equipment problems, uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollutants or hazardous materials, marine hazards with respect to offshore operations, formations with abnormal pressures, adverse weather conditions, natural or man-made disasters, premature decline of reservoirs and invasion of water into producing formations.

Drilling wells is speculative and involves significant costs that may be more than estimated and may not result in any discoveries or additions to our future production or reserves. Operational activities have numerous inherent risks and our license area is located on an island, 25km offshore mainland Tanzania, and partially in shallow water. This generally increases the operating costs, chances of delay, planning time, technical challenges and risks associated with production activities. Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to natural gas markets or delay our natural gas production.

The development of oil and natural gas projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and oilfield services, is subject to delays and cost overruns. The Company may be affected by the inability to respond to changing technological developments and remain competitive. Slower economic growth rates may materially adversely impact our operating results and financial position. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Russian-Ukraine Conflict

Russia's invasion of Ukraine in February 2022 has had wide-ranging consequences on the peace and stability of the region and the world economy. Certain countries have imposed strict financial and trade sanctions against Russia which may have far reaching effects on the global economy. Disruption of supplies of commodities from Russia had and may continue to have a significant impact on worldwide commodity prices. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain. Any negative impact on economic conditions and global markets from these developments could adversely affect our business, financial condition and liquidity. The conflict has not directly impacted the Company's operations except for as detailed in "Foreign Exchange" risks below. Nevertheless, the ongoing war induces greater uncertainties in global financial markets and supply chain systems which could lead to volatility in oil and gas prices, inflation rates, interest rates, financing costs, and shortage or delays for certain goods or services. The Company continues to assess its exposure.

Key Staff

Our performance and success are largely dependent on the ability, expertise, judgment and discretion of our management and the ability of our technical team to identify, discover, evaluate and develop reserves. We are dependent on members of our management and technical team that may not be easily replaced.

Business Risks cont.

Industry and Business Conditions cont.

Effects of Climate Change

Risks related to climate change may have an impact on the Company's operations and the Company may be subject to additional disclosure requirements in the future. The International Sustainability Standards Board issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. In addition, the Canadian Securities Administrators also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian reporting issuers. We continue to monitor developments on these reporting requirements and the impact they may have on the Company's financial position and results of operating activities in future periods.

The oil and natural gas industry is subject to varying environmental regulations and evolving views on climate change in each of the jurisdictions in which the Company may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

The Company operates in Tanzania, where extreme hot weather, heavy rains and floods or other severe weather conditions may cause operational difficulties, including downtime and increased costs of maintenance and construction. Extreme weather conditions may also impact workovers of existing wells and drilling of new wells.

As of the date of this report, it is difficult to estimate the effect of the climate change-related legislations on our business or whether additional evolving climate change legislation, regulations or other measures will be adopted in Tanzania. There are uncertainties regarding timing and effects of the emerging climate change regulations, making it difficult to accurately determine the cost impacts and effects on the Company's operations.

Contractual

We operate in a litigious environment which could result in title or contractual disputes during the ordinary course of business. The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

Marketability, Pricing and Contract Management

The marketability and price of natural gas which may be acquired, discovered or marketed by the Company will be affected by numerous factors beyond its control. The natural gas market in Tanzania is developing and there is currently limited access to infrastructure with which to serve potential new markets beyond that being constructed by the Company, Songas and TPDC. The ability of the Company to market any natural gas from current or future reserves in Tanzania may depend upon its ability to develop natural gas markets in Tanzania and the surrounding region, obtain access to the necessary infrastructure to process gas and to deliver sales gas volumes, including acquiring capacity on pipelines which deliver natural gas to commercial markets. In addition, the remaining period on the PSA, which will expire in October 2026, is presently a considerable constraint that may make new markets unlikely in the next two years.

Furthermore, in the near term, there is uncertainty with respect to the future allocation of Protected Gas volumes at the end of the Protected Gas regime on July 31, 2024 when the Gas Agreement expires with respect to Songas. The gas sales price of future deliveries of gas sold to Songas is not known at this stage.

In 2023, the PGSA with TANESCO, which was due to expire on June 30, 2023, was extended to a new expiry date of July 31, 2024. Discussions are now ongoing with TANESCO to extend the PGSA, between the Company, TPDC and TANESCO. TANESCO have confirmed their intent to extend to October 2026 however it is not known at this stage the timing for this. To mitigate these contract risks the Company continues to look to expand its industrial customer base.

The Company is also subject to market fluctuations in the prices of natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The prices that the Company receives for its natural gas affect the Company's revenue, profitability, access to capital and future growth rate. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil prices have experienced significant and sustained declines in the past and may continue to be volatile in the future; though gas prices are less volatile, they may also be significantly affected in the longer run.

The natural gas prices the Company receives from its industrial customers fluctuate with the price of Heavy Fuel Oil against which most of the Company's industrial customer contracts are priced. Prices can also be affected by gas on gas competition from other producers in Tanzania. There have been significant onshore and offshore discoveries of gas in Tanzania over the last ten years and it is expected that the development of these discoveries will increase competition in the future. There is also scope for greater government intervention on gas prices as TPDC owns and operates the majority of the gas processing and pipeline infrastructure in Tanzania.

A substantial or extended decline in both global and local oil and natural gas prices may adversely affect our business, financial condition and results of operations. Localized competition with other gas producers and alternative power sources such as hydropower could adversely impact our financial results.

Cyber-attack

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data. A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss. There can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident.

Management's Discussion & Analysis cont.

Business Risks cont.

Financial

Cost of Capital

Our long-term business plan requires substantial additional capital that we may be unable to fund out of working capital and cash flow generated from operations or raise on acceptable terms or at all in the future and which may in turn limit our ability to develop our appraisal, development and production activities. The Company's ability to meet its financing obligations or to arrange financing in the future will depend in part upon the prevailing capital market conditions as well as the Company's business performance. There can be no assurance that the Company would be successful in its efforts to meet its current commitments or arrange additional financing on terms satisfactory to the Company.

Collectability of Receivables

The Company evaluates the collectability of its receivables on the basis of payment history, frequency and predictability, as well as management's assessment of the customer's willingness and ability to pay. In the past, the Company has recorded loss allowances for receivables that did not meet the criteria for revenue recognition however no allowances have been recorded for the past three years relating to revenue.

Foreign Exchange

The Company operates internationally and is exposed to foreign exchange risk arising from currency fluctuations against the US dollar when transactions and recognized assets and liabilities of the Company are denominated in a currency that is not the US dollar functional currency. The main currencies to which the Company has an exposure are Tanzanian shillings, Euros, British pounds sterling, and Canadian dollars.

The majority of the expenditure associated with the operation of the gas distribution system is denominated in Tanzanian shillings. Whilst conversion of Tanzanian shillings into US dollars or Euros is unrestricted, the foreign exchange market for Tanzanian shillings is limited and not highly liquid, reducing the Company's ability to convert large amounts of Tanzanian shillings into US dollars or Euros at any given time. To mitigate the risk of Tanzanian shilling devaluation, the Company regularly converts Tanzanian shilling receipts into US dollars or Euros to the extent practicable. Capital stock, equity financing and any associated stock based compensation are denominated in Canadian dollars. The operational revenue and the majority of capital expenditures are denominated in US dollars. All Loan repayments are also denominated in US dollars.

The global growth slowdown and the impact of the war in Ukraine have seen an increasing decline in foreign exchange reserves due to inflationary pressures on imports in Tanzania and decreased foreign direct investment. This has given rise to decreased availability of US dollars and impaired the Company's ability to convert Tanzanian shillings to US dollars in 2023. The majority of the Company's revenue is collected in Tanzanian shillings and there is a risk that in the future the Company may not be able to convert Tanzanian shillings to US dollars as and when required. It is not known when the foreign exchange reserve deficiency in Tanzania may be remedied.

The following table illustrates cash and cash equivalents allocation between Tanzania and corporate locations:

Balances as at December 31, 2023

$'millions	Tanzanian shillings	Euros	US dollars	Other	Total
Cash and cash equivalents	41.1	10.1	48.4	2.0	101.6

Debt Financing

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed in part or in whole with debt, which may temporarily increase the Company's debt levels above industry standards. PAET currently has a Loan that includes covenants that, among other things, restrict the incurrence of additional indebtedness, payment of dividends under certain conditions, granting of liens, mergers and sale of all or a substantial part of our business or license.

Foreign Operations and Concentration Risk

Asset Concentration

The Company's natural gas reserves are currently limited to one producing property, the Songo Songo gas field, and the productive potential from this field is limited. There is no assurance that the Company will have sufficient deliverability through the existing wells to provide Protected and Additional Gas volumes, and there may be significant capital expenditures associated with any remedial work, workovers, or new drilling required to achieve optimal deliverability. In addition, any difficulties relating to the operation or performance of the Songo Songo gas field would have a material adverse effect on the Company. A loss or material reduction in production capabilities will have a material adverse effect on the total production and funds flow from operating activities of the Company.

Access to Infrastructure

The Company is dependent upon access to the Songas Infrastructure and the GoT owned NNGI to deliver gas to customers. The Company operates the Songas Infrastructure however Songas is the owner of the facilities including the 12-inch subsea and the 16-inch surface pipeline systems which transport natural gas from Songo Songo Island to Dar es Salaam. There are agreements in place to allow the Company to process and transport gas, but there is no assurance that these rights could not be challenged or access curtailed. The inability to access infrastructure would materially impair the Company's ability to realize revenue from natural gas sales.

Business Risks cont.

Foreign Operations and Concentration Risk cont.

Reputational

Our Tanzanian operations are anticipated to be the sole source of the Company's near-term revenue earnings. Due to our asset concentration, the success of our operations is dependent on positive commercial relationships with a small number of organizations (including states and parastatal organizations) and certainty with respect to our rights and obligations arising from those relationships. Any damage to our reputation due to the actual or perceived occurrence of any number of events, such as environmental incidents, could negatively impact the Company. Reputation loss may result in negative publicity and diminished or adversarial stakeholder relationships, which could lead to increased challenges in developing and maintaining community relations, decreased investor confidence, and would likely impede our overall ability to advance our projects, thereby having a material adverse impact on financial performance, cash flows and growth prospects.

Country Risk

The geographic location of the Songo Songo gas field offshore Tanzania exposes us to an increased risk of loss of revenue or curtailment of production as a result of factors generally associated with foreign operations or arising from factors specifically affecting the area in which we operate or may operate. Tanzania may be considered to be politically and/or economically unstable. Development and operational activities in Tanzania may require protracted negotiations with host governments, national oil companies and third parties, and are frequently subject to economic and political considerations, such as the risks of war, actions by terrorist or insurgent groups, expropriation, nationalization or emerging nationalization, renegotiation or nullification of existing contracts and production sharing agreements, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the award of drilling and construction contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts.

In Tanzania the state retains ownership of its minerals and consequently retains control of the exploration and production of hydrocarbon reserves. The GoT has historically been supportive of foreign investment in resource development projects in Tanzania however it has recently adopted a more conservative approach toward foreign involvement in the extractive sector, including the production, transmission, processing and marketing of natural gas. Factors such as changes in government, an increased nationalist sentiment and pressure to preserve development opportunities for local enterprises can result in legal and regulatory changes that can impact our ability to maintain our business operations.

Countries in Africa may lack the resources to effectively contain outbreaks of disease quickly. Such outbreaks if uncontained, may impact our ability to explore for natural gas, develop or produce our license areas by limiting access to qualified personnel, and increase costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and natural gas production to and from our areas of operation and diverting the time, attention and resources of government agencies which are necessary to conduct our operations. In addition, any losses we experience as a result of such outbreaks of disease which impact sales or delay production may not be covered by our insurance policies. If travel bans are implemented or extended to the countries in which we operate, or contractors or personnel refuse to travel to such locations, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow.

Corruption

Tanzania ranks 87 out of 180 on the 2023 Transparency International Corruption Perceptions Index (2022: 94 out of 180). Having assessed the Company's exposure to corruption in Tanzania, it has been concluded that the risks of the Company and/or its subsidiaries violating applicable laws prohibiting corrupt activities are mitigated or unlikely given the Company's controls relating to such risks and their effective operation. However, there is exposure to liabilities under anti-money laundering and/or anti-corruption laws, and any determination that we violated such laws could have a material adverse effect on our business. There can be no assurance that corruption may not indirectly affect or otherwise impair the Company's ability to operate in Tanzania and effectively pursue its business plan in that country.

Contractual, Regulatory and Legislation Risk

License extension

The principal asset of the Company is its indirect interest in the Songo Songo gas field under the PSA between PAET, TPDC and GoT. The PSA covers the production and marketing of natural gas from the Songo Songo gas field. The Company has the right to conduct petroleum operations on the Discovery Blocks, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of the development license of 25 years, expiring in October 2026. Under the PSA, the Company may submit a request to TPDC for a license extension, and TPDC has a contractual obligation to seek an extension at PAET's request. TPDC is expected to make this application as reasonably requested by the Company but no later than 12 months before the day on which the license expires. Upon receipt of this application, the MoE will in consultation with the Petroleum Upstream Regulatory Authority ("PURA"), consider such request on its own merit and respond accordingly, subject to the licence holder not being in default and approval of the Tanzanian Cabinet.

During Q2 2023, the Company formally requested TPDC to initiate the process of extending the development license in accordance with the terms of the PSA. The Government Negotiating Committee held a preliminary meeting with the Company in March 2024 to discuss timing around negotiations. The Company continues to seek dialogue with TPDC and the MoE seeking to expedite license extension discussions and will maintain gas sale contract discipline going forward by operating in line with our gas supply agreements.

Management's Discussion & Analysis cont.

Business Risks cont.

Contractual, Regulatory and Legislation Risk cont.

Contracts and Regulations

The Company's operations are subject to regulation and control by the GoT (see "Principal Terms of the PSA and Related Agreements"). The Company has operated in Tanzania for a number of years and believes that it has had reasonably good relations with the current GoT. Under the principal agreements the Company has the right to market and sell Additional Gas provided that such sales do not jeopardize the priority right of Songas to sell or otherwise dispose of Protected Gas. There is a risk that Songas could exercise its contractual rights, which may curtail our ability to sell Additional Gas if there is insufficient natural gas available for the required volumes of Protected Gas. There can be no assurance that present or future administrations in Tanzania will honor all principal agreements which could materially adversely affect the Company's operations or future cash flows.

PSA operations are regulated by national and parastatal organizations including the energy regulators ("PURA"), the Energy and Water Utilities Regulatory Authority ("EWURA"), and TPDC). Under the terms of the Gas Agreement with the GoT, TPDC and Songas, the Company has the right to market and sell Additional Gas. The ARGA (as defined below) provided clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas. The ARGA was initialed by all parties but remains unsigned as at the date of this report. In certain respects, the parties thereto are conducting themselves as though the ARGA is in effect. In 2017 the AGP2 (as defined below) was signed further delineating the rights of the Company to market and sell Additional Gas. If our relationships with these counterparties were to deteriorate, they might choose to exercise their contractual rights under our agreements differently and in a manner that is adverse to our interests. Management does not foresee a material risk with the conduct of the Company's business with an unsigned ARGA at this time (see "Principal Terms of the PSA and Related Agreements").

We have had, and continue to have, disagreements with TPDC and the GoT regarding certain of our rights and responsibilities under the PSA. Pursuant to the PSA, the Company plans for development and is required to submit annual work programs to TPDC for comment and subsequently to PURA who, under the Petroleum Act, 2015 ("Petroleum Act"), insist on the right to approve the budget. TPDC has also challenged our rights to cost recover a number of items under the PSA including the costs of our downstream operations; however, there are currently no disagreements that have risen to the level of a formal dispute.

There can be no assurance that all of these disagreements will be resolved in our favor or that future disagreements will not arise in Tanzania or with any host government and/or national oil companies in future projects elsewhere that may have a material adverse effect on our exploration or development activities, ability to operate, rights under our licenses and local laws or rights to monetize our interests.

Legislation

The GoT has passed several new laws in the past eight years impacting the Company's operation in Tanzania.

The National Energy Policy (2015) and the Petroleum Act, passed in 2015, provided regulatory framework over upstream, mid-stream and downstream gas activity. The Petroleum Act created PURA, a new regulator to oversee the upstream sectors, and conferred upon TPDC the status of "National Oil Company" as the sole aggregator of natural gas in the country. Article 260(3) of the Petroleum Act preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party natural gas customers. There remain differences of opinion between the Company and TPDC on the effect of certain provisions within the Petroleum Act and their application to the Company.

On October 7, 2016, the GoT issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258(I) of the Petroleum Act, which may give rise to additional uncertainty. Changes resulting from this regulation could impact the Company's ability to set gas pricing and the introduction of regulated gas pricing could result in operations becoming uneconomical and anticipated revenues could be materially affected. While the PSA has been grandfathered under the Petroleum Act, we can provide no assurances that this situation will remain unchanged in the future.

On July 15, 2017 the GoT passed into law the Natural Wealth and Resources (Permanent Sovereignty) Act, 2017, the WLMAA, 2017, and the Natural Wealth and Resources Contracts (Review and Re-Negotiation of Unconscionable Terms) Act, 2017 ("NWRCA"). The first and second of these acts are forward looking and only apply to agreements entered into on or after July 15, 2017. The GoT may argue that the NWRCA has retrospective effect in terms of its ability to renegotiate pre-existing contracts. On January 31, 2020, the government released the Natural Wealth and Resources Contracts (Review and Renegotiation of Unconscionable Terms) Regulations, 2020 which set out further guidance as to how contracts may be renegotiated. These acts contain new regulations including but not limited to regulations that all arbitration processes must be heard within Tanzania and potentially restrict the ability to move funds out of Tanzania.

In 2016, the TRA introduced significant changes to the income tax treatment of the extractive sector with separate new chapters in Part V of the ITA, 2004 for mining and for petroleum to be effective commencing in 2018. Subsequent to this, further changes were made by the WLMAA, 2017 to exclude cost oil/cost gas from inclusion in both income and expenditure. We are still evaluating the tax effects of the changes as there are a number of uncertainties and ambiguities as to the interpretation and application of certain provisions of the WLMAA, 2017 as there is an absence of regulations and guidance from TRA on the implementation of the changes. In the absence of guidance on these matters, we will continue to use what we believe are reasonable interpretations and assumptions in applying the WLMAA, 2017 for purposes of determining our tax liabilities and filing our tax returns, which interpretations and assumptions may change as we receive additional clarification and implementation guidance. As necessary, we will seek adjustments to the PSA to preserve our economic benefits. In addition, the Natural Wealth and Resources (Permanent Sovereignty) Act, 2017 and the WLMAA 2017 restrict the ability of companies to repatriate funds out of Tanzania and it is possible that the GoT will seek to argue at some stage that these provisions apply to the Company even though the Company's contracts with the GoT permit the repatriation of funds out of Tanzania.

Business Risks cont.

Contractual, Regulatory and Legislation Risk cont.

Legislation cont.

Intervening policy and legislative changes such as those described above may conflict with our pre-existing rights under the PSA and other agreements, though it remains unclear how such legislative actions will be implemented and whether and to what extent they will impact us. We are unable to predict what legislation may be proposed that might affect our business or when any such proposals, if enacted, might become effective. Such changes could require increased capital and operating expenditure and could prevent or delay certain of our operations. If, for reasons beyond our control, we are unable to maintain compliance with any legislative changes, whether in the future or past, we may have to cease operations in certain locations.

Principal Terms of the PSA and Related Agreements

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

Obligations and Restrictions

(a) The PSA covers two blocks within the Songo Songo gas field where there are gas reserves ("Discovery Blocks"). The Company has the right to conduct petroleum operations on the Discovery Blocks, 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) No sale of Additional Gas may be made from the Discovery Blocks if in the Company's reasonable judgment such sales would jeopardize 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 Blocks to secure the Company's and TPDC's obligations in respect of Insufficiency (as defined in (c) below).

(c) "Insufficiency" occurs if there is insufficient gas from the Discovery Blocks to supply the Protected Gas requirements or if the gas 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 their related liability by either replacing the Indemnified Volume (as defined in (d) below) at the price for Protected Gas with natural gas from other sources; or by paying monetary 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 $0.55/MMbtu escalated) and the amount of transportation revenues previously credited by Songas to the state electricity utility, TANESCO, for the gas volumes.

(d) 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

(e) The Company is able to utilize the Songas Infrastructure including the gas processing plant and main pipeline to Dar es Salaam. Access to the Songas Infrastructure is open and can be utilized by any third party that wishes to process or transport gas.

Revenue Sharing Terms and Taxation

(f) 75% of the gross field revenues derived from the Discovery Blocks, less processing and pipeline tariffs and direct sales taxes in any year ("field net revenue"), can be used to recover past costs incurred. Costs recovered out of field net revenue 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 MoE, provided that TPDC may to elect to participate in a development program only once and TPDC pays 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 notify the Company within 90 days of notice from the Company that the MoE has approved the Additional Gas Plan, then TPDC is deemed to have elected not to participate. If TPDC elects to participate, then it will be entitled to a ratable 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. The Company has therefore determined that to date there has been no working interest earned by TPDC. For the purpose of the reserves certification as at December 31, 2023, there are no planned drilling activities to the end of the license.

(g) The Company's long-term gas price to the power sector as set out in the ARGA between the GoT, TPDC and Songas and the PGSA is based on the price of gas at the wellhead. As at the date of this report, the ARGA remains an initialed agreement only and the parties are not in agreement with all the terms in the ARGA, however the parties are conducting themselves in terms of pricing as though the ARGA is in force.

In Q3 2017 the Company received approval of the Additional Gas Plan 2 ("AGP2") from the MoE to produce and sell increased volumes of Additional Gas. Currently the SS-10, SS-11 and SS-12 wells are connected to the NNGI and the SS-12 well started flowing gas through the NNGI in December 2018.

Management's Discussion & Analysis cont.

Principal Terms of the PSA and Related Agreements cont.

Revenue Sharing Terms and Taxation cont.

In May 2019 the Company and TPDC signed the LTGSA, initially for volumes up to 20 MMcfd which was increased subsequently to 30 MMcfd on a best endeavors basis. In 2020 the parties established a 12-month renewable agreement for the supply of volumes above 30MMcfd on an ad-hoc basis, allowing TPDC to meet fluctuating demand and compensate for shortfalls in production from their Madimba plant without being penalized due to a higher, fixed contractual limit and the subsequent take or pay penalties should the demand reduce again. The agreement has allowed the Company to supply volumes in excess of 50 MMcfd on occasion, increasing average sales volumes and revenues. In Q4 2023 the Company advised TPDC that the maximum daily quantity ("MDQ") would revert to the original and contractually agreed 20 MMcfd on the basis TPDC had not fulfilled its obligations under the 12-month renewable agreement.

(h) 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 field net revenue after cost recovery, based on the higher of the cumulative production or the average daily sales. The Profit Gas share available to the Company is a minimum of 25% and a maximum of 55%.

Average daily sales of Additional Gas MMcfd	Cumulative sales of Additional Gas Bcf	TPDC's share of Profit Gas %	Company's share of Profit Gas %
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 for 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.

(i) APT is payable when 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 PPI. 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 with 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 project economics if only limited capital expenditure is incurred.

(j) Under the Operatorship Agreement between the Company and Songas, the Company is appointed to develop, produce and process Protected Gas and operate and maintain the Songas Infrastructure, including the staffing, procurement, capital improvements, contract maintenance, maintenance of books and records, preparation of reports, maintenance of permits, waste handling, liaison with the GoT and taking 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 it neither benefits nor suffers a loss as a result of its performance.

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

Protected Gas

Under the terms of the Gas Agreement for the Songo Songo project, in the event that there is a shortfall/insufficiency in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas ($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 (258 Bcf as at December 31, 2023). 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 the end of the current term in July 2024.

Principal Terms of the PSA and Related Agreements cont.

Re-Rating Agreement

In 2011 the Company, TPDC and Songas signed the Re-Rating Agreement which evidenced an increase to the gas processing capacity of the Songas Infrastructure to a maximum of 110 MMcfd. Under the terms of the Re-Rating Agreement, the Company paid additional compensation of $0.30/mcf for sales between 70 MMcfd and 90 MMcfd and $0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of $0.59/mcf payable to Songas as set by the energy regulator, EWURA.

Although Songas notified the Company in 2014 that the Re-Rating Agreement was terminated, the parties have continued to produce, transport and sell gas volumes in line with the re-rated plant capacity. In May 2016 the Company notified TANESCO and Songas that the additional compensation for sales over 70 MMcfd would no longer be paid effective June 2016. The additional compensation was always intended to be temporary in nature until the expansion of the Songas Infrastructure, at which time Songas would apply to EWURA to obtain approval of a new tariff for the processing of volumes over 70 MMcfd. The PGSA provides for passing on to TANESCO any tariff charged to the Company should a new tariff be approved.

The parties to the Re-Rating Agreement are in the process of negotiating a replacement agreement which may address the additional compensation paid. In the interim, the processing capacity at the Songas Infrastructure remains unaltered and is fully available for utilization by the Company. This capacity is in addition to the capacity available within the NNGI.

Portfolio Gas Supply Agreement

In June 2011 the PGSA was signed (term to June 30, 2023) between TANESCO (as the buyer) and the Company (through its subsidiary PAET) and TPDC (collectively as the seller). TANESCO requested a change to the PGSA MDQ which PAET and TPDC approved effective January 29, 2018. In accordance with the PGSA, when calculating aggregate excess, extra and overtake gas through the supply period, the MDQ was reduced and the seller is now obligated, subject to infrastructure capacity, to sell a maximum of approximately 16 MMcfd (previously 26 MMcfd) for use in any of TANESCO's current power plants, except those operated by Songas at Ubungo. The PGSA, which was due to expire on June 30, 2023, was extended to a new expiry date of July 31, 2024. As part of the extension, the MDQ was increased from 16.0 MMcfd to 26.0 MMcfd. Under the agreement, the basic wellhead price of approximately $2.98/mcf increased to $3.04/mcf on July 1, 2018, to $3.10/mcf on July 1, 2019, $3.14/mcf on July 1, 2020, $3.20/mcf on July 1, 2021, $3.32/mcf on July 1, 2022 and $3.50/mcf on July 1, 2023. This agreement expires on July 31, 2024.

Long-term Gas Sales Agreement

On May 14, 2019 the Company and TPDC signed the LTGSA for an initial delivery of 20 MMcfd through the NNGI, at a price of $3.10/MMbtu as at January 1, 2019, (escalating 2% per annum) exclusive of any processing and transportation tariff associated with the NNGI. The LTGSA was amended on September 24, 2019 to increase the volumes supplied through the NNGI up to a MDQ of 30 MMcfd. In 2020 the parties established a 12-month renewable agreement for the supply of volumes above 30 MMcfd on an ad-hoc basis, allowing TPDC to meet fluctuating demand and compensate for shortfalls in production from their Madimba plant without being penalized due to a higher, fixed contractual limit and the subsequent take or pay penalties should the demand reduce again. The agreement has allowed the Company to supply volumes in excess of 50 MMcfd on occasion, increasing average sales volumes and revenues. In Q4 2023 the Company advised TPDC that the MDQ would revert to the original and contractually agreed 20 MMcfd on the basis TPDC had not fulfilled its obligations under the 12-month renewable agreement.

TPDC Back-in

TPDC has the rights under the PSA to "back in" to the Songo Songo field development and to convert this into a carried working 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 neither provided notice nor contributed any costs and the definition period has closed.

Management's Discussion & Analysis cont.

Forward-Looking Statements

This MD&A contains forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. All statements, other than statements of historical fact included in this MD&A, which address activities, events or developments that Orca expects or anticipates to occur in the future, are forward-looking statements. Forward-looking statements often contain terms such as may, will, should, anticipate, expect, continue, estimate, believe, project, forecast, plan, intend, target, outlook, focus, could and similar words suggesting future outcomes or statements regarding an outlook. More particularly, this MD&A contains, without limitation, forward looking statements pertaining to the following: the Company's expectations regarding the demand for gas supply to satisfy power demand; anticipated average gas sales, including Additional Gas sales for 2024 and average production guidance (Additional Gas) for 2024; ongoing negotiation of new commercial terms and discussion of requirements under the Gas Agreement with Songas and TPCPLC; assessment by the Company of the merits of the claim made by the seismic contractor and the timing of hearings; planned intervention in offshore well SS-7 including timing, project costs and the anticipated increased gas delivery; planned installation of a new common well inlet manifold and its anticipated timing, costs and effects; planned production logging program at various wells and its anticipated timing, costs and effects; implementation of a new work program at the Songas plant and forecasted production improvement as a result; the Company's expectation that all capital allocation decisions will be based upon prudent economic evaluations and returns; extension of the development license and the Company's expectation to continue to actively engage with the GoT to progress the license extension; maintenance of gas sale contract discipline by the Company in accordance with its gas supply agreements; anticipated award amount payable under the Long Term Retention Plan and achievement of its intended positive effects; continued accrual of participation interest until the specified date; the receipt of the payment of arrears from TANESCO; forecasts regarding future development capital spending and the anticipated source of funding; the timing and effective rate of the APT payable by the Company and credit to the cost pool; the Company's expectation that there will be no future restrictions on the movement of cash from Jersey, Mauritius or Tanzania; continued work by the Company with the GoT on alternative development plan for longer term field development; expectations regarding the recovery of workover costs from Songas under the settlement agreement and receipt of such payments in Q1 2024; the Company's plans to purchase Class B Shares under the 2023 NCIB; availability of necessary regulatory approvals; the Company's debt and interest payments and capital expenditure forecasts; the Company's expectation that it will maintain adequate working capital to cover the Company's long-term and short-term obligations; the Company does not expect to incur any loses from debtors in 2024; all planned capital expenditures can be funded from cash flow generated by current operations; the Company's expectations that no circumstances will significantly impact the Company's cash flow or liquidity other than disclosed in this MD&A, as applicable; the Company's expectations that it will be able to convert Tanzanian shillings into US dollars during and after the current foreign exchange deficiency; continued work by the Company with the GoT on alternative development plan for longer term field development; the Company's debt and interest payments and capital expenditure forecasts; availability of necessary regulatory approvals; the Company's expectations regarding supply and demand of natural gas; the Company's expectation and evaluations on the timing and results of its position, objections and appeals to the decisions and assessments of the TRA and TRAB under "Contingencies – Taxation" in this MD&A, including the timing of the filing of closing submissions by the Company and the TRA; the Company's expectations regarding changes to its tax liabilities and the results of its operations as a result of amendments made to the ITA, 2004, the WLMAA, 2017 and the implementation of further legislation; and the Company accessing its exposure to the Russian/Ukraine conflict. 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 produced profitably in the future. The recovery and reserve estimates of the Company'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, access to resources and infrastructure, 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 the Company's control, and many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by the Company, including, but not limited to: fluctuations in demand for natural gas and power supply in Tanzania; the Company's average gas sales including sale of Additional Gas and average production guidance (Additional Gas) are lower than anticipated; uncertainties involving the negotiation of new commercial terms under the Gas Agreement with Songas and TPCPLC and necessary requirements; risk that the Company may incur losses and legal expenses as a result of the claim brought forth by the seismic contractor; risk that the timing of the completion and anticipated benefits from the Company's various development programs in 2024 are different than expected; that not all capital allocation decisions will be based upon prudent economic evaluations and returns; inability to extend the development license and inability to maintain gas sale contract discipline; changes in the anticipated award amount payable under the Long Term Retention Plan and failure to achieve intended effects; accrual of participation interest is different than expected; failure to receive payments from TANESCO; changes to the timing and effective rate of the APT payable by the Company; changes to forecasts regarding future development capital spending and source of capital spending; risk of future restrictions on the movement of cash from Jersey, Mauritius or Tanzania; occurrence of circumstance or events which significantly impact the Company's cash flow and liquidity and the Company's ability cover its long-term and short-term obligations or fund planned capital expenditures; occurrence of loses from debtors in 2024; prolonged foreign exchange reserves deficiency in Tanzania; inability to convert Tanzanian shillings into US dollars as and when required; discontinuation of work by the Company with the GoT on alternative development plan for longer term field development; changes to the Company's debt and interest payments and capital expenditure forecasts; failure to obtain necessary regulatory approvals; risk that the Company does not purchase the maximum number of Class B Shares or any Class B Shares under the 2023 NCIB; future TRA assessment and the risks surrounding the Company's ability to make future deposits to object future TRA's assessments that may arise; risk that the Company will not be successful in appealing claims or decisions made by the TRA or TRAB and may be required to pay additional taxes and penalties; risks regarding the uncertainty around evolution of Tanzanian legislation; risk of unanticipated effects regarding changes to the Company's tax liabilities and its operations as a result of amendments made to the ITA, 2004, the WLMAA, 2017, the implementation of further legislation and the Company's interpretation of the same; risk of a lack of access to Songas processing and transportation facilities; risk that the Company may be unable to complete additional field development to support the Songo Songo production profile through the life of the license; risks associated with the Company's ability to complete sales of Additional Gas; negative effect on the Company's rights

Forward-Looking Statements cont.

under the PSA and other agreements relating to its business in Tanzania as a result of recently enacted legislation, as well as the risk that such legislation will create additional costs and time connected with the Company's business in Tanzania; the impact of general economic conditions in the areas in which the Company operates; civil unrest; risk of pandemic; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations; impact of local content regulations and variances in the interpretation and enforcement of such regulations; 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, oil and gas field services and skilled personnel; failure to obtain required equipment for field development; effect of changes to the PSA on the Company as a result of the implementation of new government policies for the oil and gas industry; inaccuracy in reserve estimates; incorrect forecasts in production and growth potential of the Company's assets; inability to obtain required approvals of regulatory authorities; risks associated with negotiating with foreign governments; failure to successfully negotiate agreements; risk that the Company will not be able to fulfill its contractual obligations; risk that trade and other receivables may not be paid by the Company's customers when due; inability to satisfy debt conditions of financing; the risk that the Company's Tanzanian operations will not provide near term revenue earnings; and such additional risks listed under "Business Risks" in this report. In addition, there are risks and uncertainties associated with oil and gas operations, therefore the Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by these forward-looking statements will transpire or occur, or if any of them do so, what benefits the Company 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 the Company in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors the Company believes are appropriate in the circumstances, including, but not limited to: increased demand for gas supply; the Company's average Additional Gas sales and average guidance (Additional Gas) are in line with forecasts; successful negotiation of the Gas Agreement; successful implementation of various development programs at the budgeted expenditures, including the planned intervention in the SS-7 well; all capital allocation decisions will be based upon prudent economic evaluations and returns; successful extension of the development license and maintenance of gas sale contract discipline on a go-forward basis pursuant to the Company's gas supply agreements; anticipated award amount payable under the Long Term Retention Plan and achievement of its intended positive effects; accrual of participation interest as expected; that the Company will receive payment of arrears from TANESCO; correct forecast on the timing and effective rate of the APT payable by the Company; that there will continue to be no restrictions on the movement of cash from Mauritius, Jersey or Tanzania; 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 debt and interest obligations as needed; the Company does not incur any loses from debtors in 2024; absence of circumstances or events that significant impact the Company's cash flow and liquidity; the Company will continue to be able to convert Tanzanian shillings into US dollars; long term field development will be carried out as planned; continued work by the Company with the GoT on alternative development plan for longer term field development as anticipated; timing and amount of capital expenditures and source of funding are in line with forecasts; the Company's ability to obtain necessary regulatory approvals; the ability of the Company to complete the 2023 NCIB as planned; the anticipated supply and demand of natural gas are in line with the Company's expectations; accurate assessment by the Company of the merits of claims brought forward by the seismic contractor; accurate assessment by the Company of the merits of its appeal or claims before the TRA and TRAB regarding tax assessments and penalties and expectations in respect of submission and hearing timelines; the Company's interpretation and prediction of the effects regarding changes to the Company's tax liabilities and its operations as a result of amendments made to the ITA, 2004, the WLMAA, 2017 and the implementation of further legislation is accurate in all material respects; the Company's ability to obtain revenue earnings from its operations; access to customers and suppliers; availability of employees to carry out day-to-day operations, and other resources; that the Company will successfully negotiate agreements; receipt of required regulatory approvals; the ability of the Company to increase production as required to meet demand; infrastructure capacity; commodity prices will not deteriorate significantly; the ability of the Company to obtain equipment and services in a timely manner to carry out exploration, development and exploitation activities; availability of skilled labour; 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's appeal of various tax assessments will be successful; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the effect of any new environmental and climate change related regulations will not negatively impact the Company; the Company's ability to maintain strong commercial relationships with the GoT and other state and parastatal organizations; the current and future administration in Tanzania continues to honor the terms of the PSA and the Company's other principal agreements; and other matters.

The forward-looking statements contained in this MD&A are made as of the date hereof and the Company 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.

Additional Information

Additional information relating to the Company is available on SEDAR+ at www.sedarplus.ca.

Glossary

mcf	Thousand standard cubic feet
MMcf	Million standard cubic feet
Bcf	Billion standard cubic feet
MMcfd	Million standard cubic feet per day
MMbtu	Million British thermal units
1P	Proven reserves
2P	Proven and probable reserves
kWh	Kilowatt hour
MW	Megawatt
$	US dollars
CDN$	Canadian dollars