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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, 2021. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON APRIL 20, 2022. 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 interest in the Production Sharing Agreement ("PSA") with the Tanzanian Petroleum Development Corporation ("TPDC") and the Government of Tanzania ("GoT") in the United Republic of Tanzania. This PSA covers the production and marketing of natural gas from the Songo Songo license offshore Tanzania. The PSA defines the gas produced from the Songo Songo gas field as "Protected Gas" and "Additional Gas". The Protected Gas is owned by TPDC and is sold under a 20-year gas agreement (until July 31, 2024) 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 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 ("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 CO2 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 gas the Company supplied during 2021 to Songas, TANESCO and TPDC generated approximately 45% (2020: 40%) of the electrical power and approximately 63% (2020: 66%) of all gas utilized for power generation in Tanzania.

In addition to supplying gas to TPDC, Songas and TANESCO, the Company has developed over 50 contracts to supply gas to Dar es Salaam's industrial market and is in the process of negotiating several more.

Outlook – COVID-19

There has been no significant change in the Company's business during 2021 as a result of the ongoing coronavirus pandemic ("COVID-19"). The Tanzanian government introduced new restrictions and started a vaccination program in an effort to control the spread of COVID-19 however given the steps already taken by the Company, while logistic supply chains have been stretched and delays incurred no significant impact on our operations or business results were experienced as a result of the new restrictions. The current situation is dynamic and the ultimate duration and magnitude of the impact on the Tanzanian economy and the financial effect on the Company are not known at this time.

There was a decrease in industrial sales in 2020 during the commencement of COVID-19 however there has not been a significant impact on Company operations in 2021. The Company took precautions including testing before allowing workers on site and limiting the number of people in the office at any one time and allowing employees to work from home. More recently the Company has returned to normal working practices, although lateral flow testing remains in place for visitors to the operational site on Songo Songo Island.

Estimates and judgments made by management in the preparation of these consolidated financial statements are subject to a higher degree of measurement uncertainty during this volatile period. The current volatility in commodity prices and uncertainty regarding the timing for recovery creates inherent challenges with the preparation of financial forecasts (see "Business Risks").

Financial and Operating Highlights for the Three Months and Year Ended December 31, 2021

(Expressed in $'000 unless indicated otherwise)	Three Months ended December 31 2021	Three Months ended December 31 2020	% Change Q4/21 vs Q4/20	Year ended December 31 2021	Year ended December 31 2020	% Change Ytd/21 vs Ytd/20
OPERATING						
Daily average gas delivered and sold *(MMcfd)*	**71.1**	62.8	13%	**61.1**	57.7	6%
Industrial	**14.9**	12.4	20%	**13.4**	12.7	6%
Power	**56.2**	50.4	12%	**47.7**	45.0	6%
Average price *($/mcf)*						
Industrial	**8.58**	7.56	13%	**8.09**	7.44	9%
Power	**3.41**	3.52	(3)%	**3.47**	3.47	0%
Weighted average	**4.50**	4.32	4%	**4.48**	4.34	3%
Operating netback *($/mcf)*[1]	**3.08**	3.22	(4)%	**2.93**	2.85	3%
FINANCIAL						
Revenue	**24,819**	21,980	13%	**86,022**	77,874	10%
Net income attributable to shareholders	**1,548**	7,375	(79)%	**16,370**	27,761	(41)%
per share – basic and diluted *($)*	**0.08**	0.28	(71)%	**0.81**	1.00	(19)%
Net cash flows from operating activities	**18,521**	19,369	(4)%	**40,110**	46,505	(14)%
per share – basic and diluted *($)*[1]	**0.93**	0.74	26%	**1.97**	1.67	18%
Capital expenditures[1]	**12,496**	16,315	(23)%	**26,610**	27,141	(2)%
Weighted average Class A and Class B shares *('000)*	**19,969**	26,138	(24)%	**20,317**	27,818	(27)%

	As at December 31, 2021	As at December 31, 2020	% Change
Working capital (including cash)[1]	**41,776**	74,236	(44)%
Cash and cash equivalents	**72,985**	104,190	(30)%
Long-term loan	**49,603**	54,246	(9)%
Outstanding shares *('000)*			
Class A	**1,750**	1,750	0%
Class B	**18,203**	24,388	(25)%
Total shares outstanding	**19,953**	26,138	(24)%
RESERVES[2]			
Gross Reserves *(Bcf)*			
Proved	**160**	203	(21)%
Probable	**28**	27	4%
Proved plus probable	**188**	230	(18)%
Net Present Value, discounted at 10% *($ million)*[3]			
Proved	**178**	216	(18)%
Proved plus probable	**210**	241	(13)%

[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] 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 NPV 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 2021 and Q4 2021

- Revenue increased by 13% for Q4 2021 and by 10% for the year ended December 31, 2021 compared to the same prior year periods. The increase for Q4 2021 was primarily a result of the increased sales to the industrial sector. The increase for the year ended December 31, 2021 was a result of the increased sales to both the industrial sector and power sector. Gas deliveries increased by 13% for Q4 2021 and by 6% for the year ended December 31, 2021 compared to the same prior year periods. The Q4 2021 increase is due to the 20% increase in gas deliveries to the industrial sector and the 12% increase in gas deliveries to the power sector. The increase for the year ended December 31, 2021 reflects the increase in gas deliveries of 6% to both the power and the industrial sector.
- Net income attributable to shareholders decreased by 79% for Q4 2021 and by 41% for the year ended December 31, 2021 compared to the same prior year periods. The decreases are primarily related to decreases in the reversal of loss allowances related to the lower collection of arrears from TANESCO.
- Net cash flows from operating activities decreased by 4% for Q4 2021 and by 14% for the year ended December 31, 2021 compared to the same prior year periods, primarily reflecting the changes in net income and non-cash working capital.
- Capital expenditures decreased by 23% for Q4 2021 and by 2% for the year ended December 31, 2021 compared to the same prior year periods. The capital expenditures in 2021 primarily relate to the continuation of the compression project and the commencement of the well workover program for the SS-3, SS-4 and SS-10 wells. The capital expenditures in 2020 primarily related to the flowline decoupling project and the compression project. The Company installed feed gas compression on the Songas gas processing facility to allow production volumes through the Songas Infrastructure to be sustained at approximately 102 MMcfd in the near term (3-5 years). The drilling rig was released on April 8, 2022 having completed the planned three well (SS-3, SS-4 and SS-10) workover program. The $31.6 million program included the reactivation of the SS-3 and SS-4 wells along with the installation of corrosion resistant production tubing on all three of the wells. The SS-3 well was placed on production on February 15, 2022 and the SS-10 well was returned to production on April 18, 2022 after a 36 day shut in period to accommodate the installation of down hole sand mitigation equipment and replacement production tubing. The SS-4 well remains shut in following the drilling and completion of a planned side-track wellbore to replace the original wellbore, which had been compromised by excessive sand production. Currently the SS-4 well is unable to flow naturally due to suspected excessive liquid loading associated with extensive circulating time while waiting on necessary services and equipment. The Company is sourcing a coiled tubing nitrogen unit to safely unload the excess liquid, potentially allowing the well to flow naturally. Subject to logistics and transportation from Poland, it is expected the coiled tubing equipment will be on location in Q3 2022. Together with compression facilities, and subject to demand volumes and associated natural reservoir pressure decline, the current well stock now provides the opportunity to initially increase production potential to within a range of 150 MMcfd to 160 MMcfd by also producing through the adjacent NNGI facilities on Songo Songo Island. If successful in lifting fluids from the SS-4 well, production potential will further increase.
- The Company exited the period in a strong financial position with $41.8 million in working capital (December 31, 2020: $74.2 million), cash and cash equivalents of $73.0 million (December 31, 2020: $104.2 million) and long-term debt of $49.6 million (December 31, 2020: $54.2 million). The decrease in working capital, cash and cash equivalents was primarily related to the substantial issuer bid completed in January 2021 ("2021 SIB") and the reclassification of $5.0 million of long-term debt into current liabilities as it becomes due in 2022.
- Total proved conventional natural gas reserves ("1P") and total proved plus probable conventional natural gas reserves ("2P") decreased by 21% and 18%, respectively, at December 31, 2021 compared to the prior year. The decrease is due to gross property Additional Gas production in 2021 of 22.0 Bcf (2020: 21.1 Bcf) and lower forecasted sales over the remaining life of the Songo Songo license, predominately due to the delay in new power plants coming on stream. The net present value of estimated future cash flows from 2P reserves at a 10% discount rate decreased by 13% compared to the previous year. This is mainly the result of the decrease in the time remaining to the end of the Songo Songo license together with a moderate increase in forecasted capital costs. The reserves and estimated future cash flows are based on forecasted gross property 1P Additional Gas sales volumes of 77.1 MMcfd for 2022 compared to actual results of 71.1 MMcfd for Q4-2021. 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.
- As at December 31, 2021 the current receivable from TANESCO was $2.0 million (December 31, 2020: $ nil). TANESCO's long-term trade receivable as at December 31, 2021 was $26.5 million with a provision of $26.5 million compared to $27.6 million (provision of $27.6 million) as at December 31, 2020. Subsequent to December 31, 2021 TANESCO paid the Company $8.2 million and the Company invoiced TANESCO $5.5 million for 2022 gas deliveries.
- On February 23, 2021, June 4, 2021, September 9, 2021 and November 19, 2021 the Company declared dividends of CDN$0.10 per share on each of its Class A common voting shares ("Class A Shares") and Class B subordinate voting shares ("Class B Shares") for a total of $6.4 million to the holders of record as of March 31, 2021, June 30, 2021, September 29, 2021 and December 31, 2021 (paid on April 15, 2021, July 15, 2021, October 15, 2021 and January 14, 2022, respectively).

Financial and Operating Highlights for 2021 and Q4 2021 cont.

- On January 22, 2021 the Company announced the final results of the 2021 SIB whereby the Company repurchased and cancelled 6,153,846 Class B Shares at a price of CDN$6.50 per Class B Share representing an aggregate purchase price of CDN$40.0 million and 25.2% of the total number of the Company's issued and outstanding Class B Shares and 23.5% of the total number of the Company's issued and outstanding shares.
- On June 21, 2021 the Company commenced a normal course issuer bid ("NCIB") to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. Purchases pursuant to the NCIB will not exceed 500,000 Class B Shares, representing approximately 2.74% of the total outstanding Class B Shares. The NCIB will be in effect until June 21, 2022 (or until such time as the maximum number of Class B Shares have been purchased). As at April 20, 2022, 41,200 Class B Shares have been purchased and canceled by the Company pursuant to the NCIB.
- On February 24, 2022 the Company declared a dividend of CDN$0.10 per share on each of its Class A Shares and Class B Shares for a total of $1.6 million to the holders of record as of March 31, 2022 paid on April 15, 2022.
- 2022 production started strongly, with gross sales of Additional Gas averaging 74 MMcfd in January.
- The Company forecasts average gross gas sales of 70-76 MMcfd during 2022 representing a 10 MMcfd, or approximately 16%, increase to the prior forecasts of 60-66 MMcfd. The increased gas demand forecast is primarily driven by encouraging discussions with the MoE, TPDC and TANESCO to increase gas supply to new power generation facilities expected to be commissioned in 2022.

Oil and Gas Advisory

The Company's conventional natural gas reserves as at December 31, 2021 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, 2021 and December 31, 2020 and preparation date of February 24, 2022 and February 23, 2021 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 royalties, 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, 2021 and December 31, 2020, 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 before deduction of royalties owned by others and without including any royalty interests of the Company, and are based on the Company's 92.07% ownership interest in the reserves following the transaction with Swala Oil & Gas (Tanzania) plc. 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.sedar.com.

"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 referenced 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.

Management's Discussion & Analysis cont.

Operating Volumes

The average gross daily sales volume increased by 13% for Q4 2021 and by 6% for the year ended December 31, 2021 over the comparable prior year periods. The increase in gross sales volume was primarily due to increased sales to both the power and the industrial sectors.

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	
	2021	2020	2021	2020
Gross sales volume *(MMcf)*				
Industrial sector	**1,371**	1,137	**4,882**	4,633
Power sector	**5,168**	4,640	**17,430**	16,484
Total volumes	**6,539**	5,777	**22,312**	21,117
Gross daily sales volume average *(MMcfd)*				
Industrial sector	**14.9**	12.4	**13.4**	12.7
Power sector	**56.2**	50.4	**47.7**	45.0
Gross daily sales volume average total	**71.1**	62.8	**61.1**	57.7

Industrial Sector

Industrial sector gross daily sales volumes increased by 20% for Q4 2021 and by 6% for the year ended December 31, 2021 over the comparable prior year periods. The increases were a result of increased consumption due to an overall increase in demand for services and products and by an increase in the number of industrial customer contracts entered into during the year.

Power Sector

Power sector sales gross daily sales volumes increased by 12% for Q4 2021 and by 6% for the year ended December 31, 2021 over the comparable prior year periods. The increases were primarily due to increased gas sales to TPDC though the NNGI.

Protected Gas Volumes

Protected Gas volumes increased by 16% to 3,854 MMcf (41.9 MMcfd) for Q4 2021 compared to 3,335 MMcf (36.3 MMcfd) for Q4 2020 and by 9% to 13,255 MMcf (36.3 MMcfd) for the year ended December 31, 2021 compared to 12,138 MMcf (33.2 MMcfd) for the year ended December 31, 2020. 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	2021	2020	2021	2020
Average sales price				
Industrial sector	**8.58**	7.56	**8.09**	7.44
Power sector	**3.41**	3.52	**3.47**	3.47
Weighted average price	**4.50**	4.32	**4.48**	4.34

Commodity Prices cont.

Industrial Sector

The average industrial sales price increased by 13% for Q4 2021 and by 9% for the year ended December 31, 2021 over the comparable prior year periods. The increase in prices is 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 decreased by 3% for Q4 2021 and remained unchanged for the year ended December 31, 2021 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 reconciliation of gross field revenue to Company operating revenue and revenue is detailed below:

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Industrial sector	**11,764**	8,589	**39,477**	34,485
Power sector	**17,649**	16,347	**60,445**	57,267
Gross field revenue	**29,413**	24,936	**99,922**	91,752
TPDC share of revenue	**(6,010)**	(2,822)	**(22,285)**	(19,685)
Company operating revenue	**23,403**	22,114	**77,637**	72,067
Current income tax adjustment	**1,416**	(134)	**8,385**	5,807
	24,819	21,980	**86,022**	77,874

Revenue increased by 13% for Q4 2021 and by 10% for the year ended December 31, 2021 over the comparable prior year periods. The increases are primarily a result of increased sales to both the industrial and the power sectors together with increase in the weighted average price in relation to sales to the industrial sector.

The average Additional Gas sales volumes for the quarters and for the years ended December 31, 2021 and December 31, 2020 were above 50 MMcfd, which entitled the Company to a 55% share of Profit Gas revenue. The Company was allocated a total of 76% of the Additional Gas net field revenue for Q4 2021 (Q4 2020: 88%) and a total of 75% of the Additional Gas net field revenue for the year ended December 31, 2021 (year ended December 31, 2020: 77%).

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	2021	2020	2021	2020
Operating costs	**560**	844	**2,042**	2,539
Tariff for processing and pipeline infrastructure	**2,437**	2,056	**8,222**	7,009
Ring-main distribution costs	**259**	620	**1,989**	2,356
	3,256	3,520	**12,253**	11,904

Included in operating costs are 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 34% for Q4 2021 and by 20% for the year ended December 31, 2021 compared to the same prior year periods, primarily due to decreased expenditure on reserve and resource evaluation. The amount paid under the tariff for processing and pipeline infrastructure increased by 19% for Q4 2021 and by 17% for the year ended December 31, 2021 compared to the same prior year periods, primarily as result of increased volumes processed and delivered through the Songas Infrastructure. Ring-main distribution costs decreased by 58% for Q4 2021 and by 16% for the year ended December 31, 2021 compared to the same prior year periods, primarily as a result of reduced spending on expansion and lower maintenance costs associated with the ring-main which transports the gas primarily to industrial customers.

Operating Netback

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

	Three Months ended December 31		Year ended December 31	
$/mcf	2021	2020	2021	2020
Gas price – Industrial	**8.58**	7.56	**8.09**	7.44
Gas price – Power	**3.41**	3.52	**3.47**	3.47
Weighted average price for gas	**4.50**	4.32	**4.48**	4.34
TPDC Profit Gas entitlement	**(0.92)**	(0.49)	**(1.00)**	(0.93)
Production, distribution and transportation expenses	**(0.50)**	(0.61)	**(0.55)**	(0.56)
Operating netback	**3.08**	3.22	**2.93**	2.85

The operating netback decreased by 4% for Q4 2021 and increased by 3% for the year ended December 31, 2021 over the comparable prior year periods. The decrease in Q4 2021 is the result of lower capital expenditure than in Q4 2020 resulting in a higher TPDC Profit Gas entitlement, partially offset by the increase in gas prices to the industrial sector. The increase for the year ended December 31, 2021 over the comparable prior year period is mainly due to the increase in gas price to the industrial sector.

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.

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Tanzania	**1,891**	2,184	**6,946**	7,052
Corporate	**1,423**	943	**5,042**	6,540
	3,314	3,127	**11,988**	13,592

General and administrative expenses are detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Employee and related costs	**1,833**	1,600	**6,919**	7,499
Office costs	**785**	1,206	**2,716**	4,006
Marketing and business development costs	**327**	130	**967**	879
Reporting, regulatory and corporate	**369**	191	**1,386**	1,208
	3,314	3,127	**11,988**	13,592

General and administrative expenses averaged $1.1 million per month during Q4 2021 (Q4 2020: $1.0 million) and $1.0 million per month for the year ended December 31, 2021 (year ended December 31, 2020: $1.1 million). The 8% decrease in employee and related costs for the year ended December 31, 2021 over the comparable prior year period was mainly due to termination payments to senior management in 2020. The 32% decrease in office costs for the year ended December 31, 2021 over the comparable prior year period was a result of the decision in Q3 2020 to focus on Tanzanian operations by reducing head office staff, office space and related costs. The 10% increase in marketing and business development costs for the year ended December 31, 2021 over the comparable prior year period was a result of expanding the corporate social responsibility program in Tanzania. The 15% increase in reporting, regulatory and corporate costs for the year ended December 31, 2021 over the comparable prior year period was due to increase in costs related to professional and legal services.

Stock Based Compensation

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

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Stock appreciation rights ("SARs")	**(123)**	681	**(585)**	671
Restricted stock units ("RSUs")	**24**	146	**9**	403
	(99)	827	**(576)**	1,074

As at December 31, 2021 a total of 746,166 SARs were outstanding (December 31, 2020: 1,242,166). No new SARs were issued, 412,667 SARs were exercised, and 83,333 SARs were forfeited during 2021. As at December 31, 2021 a total of 76,366 RSUs were outstanding (December 31, 2020: 133,200). No new RSUs were issued, 47,501 RSUs were exercised, and 9,333 RSUs were forfeited during 2021.

As SARs and RSUs are settled in cash, they are re-valued at each reporting date using the Black-Scholes option pricing model with the resulting liability being recognized in trade and other liabilities. In the valuation of SARs and RSUs at the reporting date, the following assumptions have been made: a risk-free rate of interest of 1.0%, stock volatility of 26.6% to 37.8%, 5% forfeiture and a closing price of CDN$5.40 per Class B Share. The valuation of outstanding SARs and RSUs awards is increased to reflect the dividends paid between the award date and the exercise date.

As at December 31, 2021 a total accrued liability of $1.1 million (December 31, 2020: $2.2 million) has been recognized in relation to SARs and RSUs. The Company recognized $0.1 million for Q4 2021 as stock based compensation recovery (Q4 2020: $0.8 million as stock based compensation expense) and $0.6 million for the year ended December 31, 2021 as stock based compensation recovery (year ended December 31, 2020: $1.1 million as stock based compensation expense).

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, 2021 the estimated proved reserves remaining to be produced over the term of the PSA as determined by McDaniel in their report dated February 24, 2022 with an effective date of December 31, 2021 and prepared in accordance with NI 51-101 and the COGE Handbook were 160 Bcf (December 31, 2020: 203 Bcf). The average depletion rate was $0.71/mcf for the year ended December 31, 2021 compared to $0.69/mcf for the comparable prior year.

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Oil and natural gas interests	**4,646**	4,078	**15,779**	14,830
Office and other	**6**	11	**37**	94
Right-of-use assets	**72**	73	**290**	397
	4,724	4,162	**16,106**	15,321

The depletion charge for natural gas interests increased by 14% for Q4 2021 and by 6% for the year ended December 31, 2021 over the comparable prior year periods. The increases were due to increased gas produced and sold, additional capital expenditure, and a reduction in estimated proved reserves.

Finance Income and Expense

Finance income is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Interest income	**25**	124	**133**	844
Investment income	**–**	–	**–**	305
	25	124	**133**	1,149

At December 31, 2021 and December 31, 2020 the Company did not have investments in short-term bonds. The $0.3 million investment income for 2020 relates to the interest earned on short-term investment bonds.

Finance expense is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Base interest expense	**1,476**	1,467	**5,982**	5,830
Participation interest expense	**372**	889	**920**	1,971
Lease interest expense	**9**	14	**43**	86
Interest expense	**1,857**	2,370	**6,945**	7,887
Net foreign exchange loss (gain)	**274**	58	**628**	(438)
Interest on tax assessment	**588**	–	**588**	–
Indirect tax	**212**	203	**1,826**	1,873
	2,931	2,631	**9,987**	9,322

Finance Income and Expense cont.

Base and participation interest expense relate to the long-term loan ("Loan") from the International Finance Corporation ("IFC") to the Company's subsidiary operating in Tanzania, PanAfrican Energy Tanzania Limited ("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 until October 15, 2026 regardless of whether the Loan is repaid prior to its contractual maturity date. The decrease in participation interest expense for the year ended December 31, 2021 over the comparable prior year period is primarily a consequence of PAET's capital expenditure program, which has reduced the net cash flows on which the participation interest expense is based compared to the same prior year period.

Net foreign exchange gains and losses are the result of transactions in foreign currencies recorded at the rate of exchange prevailing on the date of such transactions. 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 interest on tax assessment represents the Company's share of the amount in dispute with respect to interest on depreciation disallowed by the TRA for expenditures in relation to completing well SS-10 in 2009 and 2010 and well SS-12 in 2015 and 2016 (see "Contingencies – Taxation"). The indirect tax is for value added tax ("VAT") associated with invoices to TANESCO under the take or pay provisions within the PGSA and for interest on late payments.

(Reversal of) Loss Allowance

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Reversal of loss allowance	**–**	(3,478)	**(3,762)**	(20,951)
Loss allowance	**1,188**	–	**1,188**	5,337
	1,188	(3,478)	**(2,574)**	(15,614)

The reversal of loss allowance of $3.8 million during 2021 (2020: $21.0 million) follows collection of: (i) TANESCO arrears of $1.1 million (2020: $19.9 million) which had been previously allowed for and represents the excess of receipts over gas sales invoiced during the year; (ii) Songas operatorship arrears of $1.9 million (2020: $1.1 million) which had been previously allowed for; and (iii) collection of $0.8 million (2020: $ nil) of indirect taxes related to the receipt of funds for the TANESCO 2016 take or pay invoice that had been previously allowed for.

The loss allowance of $1.2 million during 2021 is for: (i) $0.5 million, being the amount in dispute with the Tanzanian Revenue Authority ("TRA") with respect to withholding tax on services performed outside Tanzania by non-resident persons in 2010 and 2015-16; and (ii) $0.7 million with respect to impairment of Swala convertible preference shares. The loss allowance for 2020 related to $5.3 million the TRA collected via an Agency Notice which obligated the Company's bank in Tanzania to release funds in favor of the TRA. This $5.3 million was initially considered recoverable, however in 2021 the Tanzanian Court of Appeal ("CAT") ruled against an appeal filed by the Company in 2020 and the Company, with advice from its legal counsel, decided not to proceed further on this matter.

For additional context regarding the reversal of loss allowance and the loss allowance for receivables, please see the Company's audited financial statements for the fiscal year ended December 31, 2020, and the Company's Q3 2020 MD&A and Q3 2020 interim financial statements and notes available on SEDAR at www.sedar.com or the Company's website.

Tax

Income Tax

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Current tax	**3,736**	816	**10,192**	7,384
Deferred tax	**2,743**	2,296	**6,534**	3,356
	6,479	3,112	**16,726**	10,740

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, 2021 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 $25.0 million (December 31, 2020: $18.5 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.

Additional Profits Tax ("APT")

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
APT	**1,214**	589	**4,609**	4,054

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 revenues over the term of the PSA. The forecast takes into account the timing of future development capital spending. As at December 31, 2021 the current portion of APT payable was $8.5 million (December 31, 2020: $11.5 million) with a long-term APT payable of $20.9 million (December 31, 2020: $24.8 million). APT of $11.5 million was paid in Q1 2021 based on the 2020 results (Q1 2020: $11.9 million based on 2019 results).

The effective APT rate of 17.3% (Q4 2020: 17.1%) has been applied to the Company's share of Profit Gas revenue of $6.8 million for Q4 2021 (Q4 2020: $3.4 million), and an average effective rate of 17.3% (2020: 16.8%) has been applied to Company's share of Profit Gas revenue of $26.7 million for the year ended December 31, 2021 (year ended December 31, 2020: $24.1 million). Accordingly, $1.2 million for the quarter ended December 31, 2021 (Q4 2020: $0.6 million) and $4.6 million for the year ended December 31, 2021 (year ended December 31, 2020: $4.1 million) of APT has been recorded in the Consolidated Statements of Comprehensive Income.

Working Capital

Working capital as at December 31, 2021 was $41.8 million (December 31, 2020: $74.2 million) and is detailed in the table below (also see "Non-GAAP financial measures and ratios"):

	As at December 31			
$'000		2021		2020
Cash and cash equivalents		**72,985**		104,190
Trade and other receivables				
Songas	**8,776**		6,624	
TPDC	**5,603**		7,417	
TANESCO	**2,042**		–	
TRA	**-**		5,337	
Industrial customers and other receivables	**15,487**		10,960	
Loss allowance	**(1,177)**	**30,731**	(8,458)	21,880
Prepayments		**1,133**		898
		104,849		126,968
Trade and other liabilities				
TPDC share of Profit Gas revenue[1]	**21,911**		25,570	
Songas	**1,899**		2,062	
Deferred income – take or pay contracts	**5,215**		–	
Other trade payables and accrued liabilities	**17,751**		11,655	
Current portion of long-term loan	**5,000**		–	
Current portion of APT	**8,461**	**60,237**	11,489	50,776
Tax payable		**2,836**		1,956
		63,073		52,732
Working capital		**41,776**		74,236

[1] The balance of $21.9 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 $15.6 million in 2021 (2020: $14.9 million).

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 cash, and the risk that trade and other receivables may not be paid when due. The Company mitigates these risks by (i) holding the majority of its cash outside of Tanzania in reputable international financial institutions primarily in Jersey and Mauritius which reduces geo-political risk; and (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. 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 are derecognized 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, including forecast debt and interest payments ($11.1 million) and capital expenditure ($50.0 million) for 2022. The Company hasn't incurred any losses from debtors in 2021 and does not expect to incur any losses from debtors in 2022. The Company maintains adequate cash and cash equivalents on hand to ensure it can meet all its capital expenditure obligations and deal with possible fluctuations in liquidity from operational problems including any potential impact from COVID-19. The Company does not anticipate any circumstances that are reasonably likely to occur that could significantly impact the Company's cash flows and liquidity.

Working Capital cont.

TANESCO Receivable

As at December 31, 2021 the current receivable from TANESCO was $2.0 million (December 31, 2020: $ nil), which was subsequently paid in 2022. During 2021 the Company invoiced TANESCO $23.9 million (2020: $23.3 million) for gas deliveries and received $22.9 million (2020: $43.2 million) in payments. Based on the consistent payments from TANESCO, the Company: (i) recognized all amounts invoiced for gas deliveries in 2021 and 2020 as revenue; and (ii) recognized $1.1 million during the year (2020: $19.9 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.

The TANESCO long-term receivable as at December 31, 2021 was $26.5 million with a provision of $26.5 million compared to $27.6 million (with a provision of $27.6 million) as at December 31, 2020. In 2021 the Company invoiced TANESCO $6.7 million (2020: $6.5 million) under the take or pay provision within the PGSA; this invoice has not been recognized as it does not meet revenue recognition criteria with respect to assurance of collectability. Subsequent to December 31, 2021 the Company has invoiced TANESCO $5.5 million for 2022 gas deliveries and TANESCO has paid the Company $8.2 million.

Capital Expenditures

The capital expenditures (see "Non-GAAP financial measures and ratios") in 2021 primarily related to the installation of compression facilities and well workover planning and design. The capital expenditures in 2020 primarily related to the flowline construction and the compression project.

	Three Months ended December 31		Year ended December 31	
$'000	2021	2020	2021	2020
Pipelines, well workovers and infrastructure	**12,494**	16,310	**26,596**	27,117
Other capital expenditures	**2**	5	**14**	24
	12,496	16,315	**26,610**	27,141

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 at Songo Songo Island. Any additional significant capital expenditure in Tanzania is discretionary.

As at the date of this report, the Company's only significant contractual commitment is in relation to contracts for the workover program. The Company concluded the onshore well remediation program comprising three wells (SS-3, SS-4 and SS-10) in April 2022. The SS-3 well was shut in 2012 due to excessive corrosion and sustained annulus pressure. Having returned to production on February 15, 2022, the SS-3 well has since been continually producing an average of 10 MMcfd. The SS-4 well was suspended in 2019 after it started producing sand. Currently not producing due to excessive liquid loading, the Company intends to mobilize a coiled tubing unit to lift the liquids and allow the SS-4 well to flow naturally. However, a recent upturn in industry activity means a suitable unit is unlikely to be available in Tanzania until Q3 2022. The SS-10 well was still producing prior to the workover program, but was also affected by progressive corrosion of its production tubing which would have ultimately threatened its safe operation. Following considerable delays due to downhole complications necessitating extensive milling and fishing, the workover of the well was completed on April 7, 2022, and was successfully returned to production on April 18, 2022. The total estimated gross cost for the workovers was $21.4 million. However, following considerable logistical and customs delays, increased service company costs against estimates, and surface and down hole technical issues, the total cost of the program increased to $31.6 million. As of December 31, 2021, $13.9 million was incurred with $9.7 million incurred in Q1 2022 and the remaining $8.0 million forecasted to be paid by the end of Q2 2022. Subject to ongoing negotiations and approvals, further expenditure may be necessary in mobilizing the coiled tubing nitrogen unit to restart production from the SS-4 well.

In March 2022, one month ahead of schedule, the Company completed construction and commissioning of feed gas compression facilities on the Songas gas processing facility. The installation of three 35 MMcfd reciprocating compressors was designed to ensure maximum gas throughput of the Songas gas processing plant at arrival pressures as low as 38 bar. The sustainability of such production is subject to gas demand in the forthcoming years, however internal forecasts predict this may be achievable to October 2026 (the end of the current PSA). The original lump sum turnkey price for the contract was $38.0 million, however price variations due to increased costs of sea freight, a requirement to increase on site power generation capacity, design changes and brief scheduling delays to avoid an extended plant shut down over the 2021 Christmas and New Year period, have seen the total project costs increase to $41.7 million, of which $40.5 million was incurred as of December 31, 2021 with forecast outstanding expenditures of $1.2 million expected to be paid in Q2 2022.

In order to de-risk both the future development drilling and potential exploration drilling of prospective resources, the Company intends to carry out a 3D seismic acquisition program in 2022, budgeted at $20.0 million. Following an open tender process, the Company has issued a recommendation for award of contract and is in the process of negotiating terms and program timing with the preferred service provider. Physical execution of the acquisition is planned for Q3 2022, but is dependent on obtaining environmental approvals in time to take advantage of suitable weather windows.

Long-term Receivables

	As at December 31	
$'000	2021	2020
VAT – Songas workovers	**2,205**	2,205
Lease deposit	**10**	9
	2,215	2,214

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 enabling the Company 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. The Company continues to take formal action to collect the workover costs and filed an initial arbitration claim in October 2021, on behalf of the Company and its partner, TPDC, in accordance with the agreement. Amounts not collected will be pursued through the mechanisms provided in the agreements with Songas.

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

	As at December 31	
$'000	2021	2020
Total amounts invoiced to TANESCO	**119,168**	111,234
Trade receivable – TANESCO	**(2,042)**	–
Unrecognized amounts not meeting revenue recognition criteria[1]	**(90,634)**	(83,685)
Loss allowance	**(26,492)**	(27,549)
	–	–

[1] The amount includes invoices for interest on late payments and invoices relating to differences between natural gas contracted for delivery versus gas taken by TANESCO.

Long-term Loan

In 2015 PAET took out the Loan with the IFC, a member of the World Bank Group, for $60 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 and one final payment of $25.2 million 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 the guarantee obligation in 2025. Pursuant to the sale of a non-controlling interest in PAE PanAfrican Energy Corporation ("PAEM"), the parent company of PAET, the Company agreed with the IFC to reduce the outstanding amount of the Loan by the percentage interest sold of 7.9% ($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.

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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) is 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 2021 SIB of CDN$40.0 million in January 2021 (CDN$50.0 million pursuant to the substantial issuer bid completed in 2020 ("2020 SIB")) the Company purchased and canceled 6,153,846 Class B Shares (2020: 7,692,297 Class B Shares). Pursuant to the NCIB commenced on June 21, 2021, the Company has purchased and canceled 30,900 Class B Shares as of December 31, 2021 and 41,200 Class B Shares as of April 20, 2022. 1,750,495 Class A Shares and 18,202,714 Class B Shares were outstanding as at December 31, 2021 and 1,750,495 Class A Shares and 18,192,414 Class B Shares were outstanding as at April 20, 2022. 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	2021	2020	2021	2020
Operating activities				
Net income	**1,915**	7,698	**17,963**	29,121
Non-cash adjustments	**12,016**	2,791	**30,074**	25,637
Interest expense	**1,857**	2,370	**6,945**	7,887
Changes in non-cash working capital[1]	**2,733**	6,510	**(14,872)**	(16,140)
Net cash flows from operating activities	**18,521**	19,369	**40,110**	46,505
Net cash (used in) from investing activities	**(13,629)**	28,633	**(24,985)**	17,720
Net cash used in financing activities	**(3,269)**	(42,386)	**(45,949)**	(54,408)
Increase (decrease) in cash	**1,623**	5,616	**(30,824)**	9,817

[1] See Consolidated Statements of Cash Flows.

The Company's net cash flows from operating activities decreased by 4% for Q4 2021 and by 14% for the year ended December 31, 2021 over the comparable prior year periods. The decreases were primarily a result of a decrease in the reversal of loss allowances for receivables due to lower payments from TANESCO. The decrease in net cash (used in) from investing activities for the year ended December 31, 2021 over the comparable prior year period was mainly a result of the conversion of $44.8 million short-term bonds to cash in 2020. The decrease in net cash used in financing activities for the year ended December 31, 2021 over the comparable prior period was primarily a result of difference in the amount of the 2021 SIB of $31.9 million compared to the 2020 SIB of $38.2 million.

Related Party Transactions

The Chair of the Company's Board of Directors is counsel to 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 $65 thousand for the quarter ended December 31, 2021 (Q4 2020: $0.3 million) and $0.3 million for the year ended December 31, 2021 (year ended December 31, 2020: $1.0 million). As at December 31, 2021 the Company had a total of $0.1 million (December 31, 2020: $0.1 million) recorded in trade and other liabilities in relation to this related party.

Substantial Issuer Bid, Normal Course Issuer Bid and Dividends

During Q1 2021 the Company repurchased and canceled 6,153,846 Class B Shares (Q1 2020: 7,692,297) at a weighted average price of CDN$6.50 per Class B Share under the 2021 SIB (2020 SIB: CDN$6.50). This resulted in an aggregate purchase of CDN$40.0 million (2020 SIB: CDN$50.0 million) of Class B Shares representing 25.2% (2020 SIB: 23.6%) of the Company's issued and outstanding Class B Shares and 23.5% (2020 SIB: 22.4%) of the total number of the Company's issued and outstanding shares. Total cash payments of $31.9 million (2020 SIB: $38.2 million) were applied to the capital stock and accumulated income accounts.

On June 21, 2021 the Company commenced a NCIB to purchase Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. Purchases pursuant to the NCIB are made by Research Capital Corporation ("Research Capital") on behalf of the Corporation and will not exceed 500,000 Class B Shares, representing approximately 2.74% of the total outstanding Class B Shares. The NCIB will be in effect until June 21, 2022 (or until such time as the maximum number of Class B Shares have been purchased). Purchases of Class B Shares are 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 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 NCIB will be canceled. As of December 31, 2021 30,900 Class B Shares were repurchased by the Company pursuant to the NCIB at an average price per Class B Share of CDN$5.17 and as of April 20, 2022, 41,200 Class B Shares have been purchased by the Company pursuant to the NCIB at an average price per Class B Share of CDN$5.20. Shareholders may obtain a copy of the notice regarding the NCIB filed with the TSXV from the Company without charge.

All issued capital stock is fully paid.

Dividend Summary

Declaration date	Record date	Payment date	Amount per share (CDN$)
February 24, 2022	March 31, 2022	April 15, 2022	0.10
November 9, 2021	December 31, 2021	January 14, 2022	0.10
September 9, 2021	September 29, 2021	October 15, 2021	0.10
June 4, 2021	June 30, 2021	July 15, 2021	0.10
February 23, 2021	March 31, 2021	April 15, 2021	0.10
November 19, 2020	December 31, 2020	January 15, 2021	0.08
September 17, 2020	September 30, 2020	October 15, 2020	0.08
June 22, 2020	June 30, 2020	July 15, 2020	0.06
February 25, 2020	March 31, 2020	April 30, 2020	0.06

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 Italy Inc.1	British Virgin Islands	100%
Orca Exploration Italy Onshore Inc.[1]	British Virgin Islands	100%
PAE PanAfrican Energy Corporation ("PAEM")	Mauritius	92%
PanAfrican Energy Tanzania Limited	Jersey	92%
Orca Exploration UK Services Limited	United Kingdom	100%

[1] The companies were wound up during 2020.

Management's Discussion & Analysis cont.

Non-Controlling Interest

The Company sold 7.9% (7,933 Class A common shares) of PAEM to a wholly owned subsidiary of Swala Oil & Gas (Tanzania) plc. ("Swala") in 2018 for $15.4 million cash and $4.0 million of Swala convertible preference shares ("Preference Shares") pursuant to a share purchase agreement. The Preference Shares entitle 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 is at the discretion of Swala based on funds available, however, the liability accrues if any amount is unpaid when due. If any distributable amount remains unpaid after December 31, 2021, the Company may demand settlement and Swala is obligated to comply by transferring and returning the Class A common shares of PAEM sold to Swala. The aggregate value of these shares will equal the amount of the outstanding distributions. As at December 31, 2021, the Company has not received any distributions or recorded any amount receivable related to the Preference Shares.

Swala is 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 does not redeem the required number of Preference Shares for cash, Swala is obligated to redeem the Preference Shares by transferring and returning the Class A common shares of PAEM sold to Swala's wholly owned subsidiary. The aggregate value of these Class A common shares will equal the amount of any outstanding redemption. As of December 31, 2021, the Company recorded $0.7 million as a loss allowance with respect to Preference Shares.

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

	As at December 31	
$'000	2021	2020
Balance, beginning of year	**1,523**	163
Share of post-disposition income	**1,593**	1,360
Balance, end of year	**3,116**	1,523

Contingencies

Taxation

					As at December 31	
Amounts in $'millions					2021	2020
Area	Period	Reason for dispute	Principal	Interest	Total	Total
Pay-As-You-Earn ("PAYE") tax	2008-10	PAYE tax on grossed-up amounts in staff salaries which are contractually stated as net.	**0.3**	**-**	**0.3**[(1)]	1.6
Withholding tax ("WHT")	2005-09	WHT on services performed outside of Tanzania by non-resident persons.	**1.0**	**0.6**	**1.6**[(2)]	8.7
Income tax	2008-09, 2011-17	Deductibility of capital expenditures and expenses (2012, 2015 and 2016), additional income tax (2008, 2011 and 2012), tax on repatriated income (2012 to 2016), foreign exchange rate application (2013, 2014 and 2015), underestimation of tax due (2014 and 2016) and methodology of grossing up income taxes paid (2015 to 2017).	**34.2**	**17.5**	**51.7**[(3)]	52.1
VAT	2012-18	VAT already paid (2012 to 2014), VAT on imported services (2015 and 2016); interest on VAT decreasing adjustments and input VAT on services (2017 and 2018).	**0.2**	**1.2**	**1.4**[(4)]	6.8
			35.7	**19.3**	**55.0**	69.2

Contingencies cont.

Taxation cont.

During Q2 2021 the Company paid the TRA $1.8 million as a deposit against the disputed taxes including PAYE tax, WHT, income tax and VAT for the years 2012-16, an amount agreed upon in order for TRA to admit the outstanding tax objections. In Q3 2021, the CAT delivered its judgment on an appeal instituted by the Company on the appealability of a one-third deposit required to admit objections for the 2012 year of income. The CAT decided that the matters are not tax decisions and are therefore not appealable. The Company filed a notice of motion for review of the decision at the same court and is awaiting a hearing. The decision, however, will not affect the position on admission of objections for the years of 2012-16.

During 2020 the TRA issued an Agency Notice for $5.3 million, obligating PAET's commercial bank in Tanzania to release funds in favor of the TRA with regards to the output VAT on SSI operatorship services (2008-10). In Q3 2020, the Company filed an appeal with the CAT and recorded the $5.3 million as other receivables and fully allowed for the amount on the Company's financial statements. Subsequently, during Q3 2021, the CAT ruled in favor of the TRA on the Company's appeal. Management, with advice from its legal counsel, decided not to proceed further on this matter.

During Q4 2021 the TRA issued a new assessment with regards to 2017 income tax ($6.4 million). The Company has objected TRA's incorrect methodology of grossing up income taxes already paid ($6.4 million) and the issue of imposing interest on deemed delayed payment ($0.1 million) and is awaiting a TRA response.

In Q4 2021, the Company recorded an allowance of $0.6 million with respect to interest on depreciation of disallowed costs of completion of wells SS-10 (2009-10) and SS-12 (2015-16). In addition, the Company recorded an allowance of $0.5 million with respect to WHT on services performed outside Tanzania by non-resident persons (2010 and 2015-16). These disputes are no longer represented in the table above.

In Q4 2021, the Company recorded an additional provision of approximately $2.2 million.

In Q4 2021, further to issuing its objections to TRA's 2015-16 assessments, the Company received determination letters whereby the TRA agreed to drop their claims with regards to WHT on interest on the IFC Loan and management fees (2015-16) and PAYE on grossed up salaries (2015-16) in the amounts of $0.9 million and $1.4 million, respectively. The aforementioned disputes are no longer represented in the table above. Additionally, with the advice from its legal and tax counsels, it was established that four of the assessments with respect to 2011 ($0.2 million), 2013 ($0.2 million), 2014 ($3.3 million) and 2015-16 ($0.4 million) income tax, which were previously presented as contingencies, were overridden by four other assessments, effectively presenting duplicating assessments, for the respective years of income. This has now been amended accordingly in the taxation contingency table above.

Subsequent to December 31, 2021, 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 2012-16, tax on repatriated income for the years of 2012 and 2013, and VAT for the years of 2015-16. In Q2 2022, these matters came for hearing and, at the request from the TRA, the TRAB granted an order that these matters be withdrawn to allow the TRA to further review and issue determination letters. The matters are expected to appear for a status review in May 2022. In addition, the Company paid the TRA $0.7 million as a deposit against disputed income tax for the year of income of 2017.

During 2020, the TRA conducted audits of 2017 and 2018 and issued two assessments with regards to VAT ($1.2 million) and WHT ($0.01 million). The Company has conceded to the TRA with respect to the WHT assessment ($0.01 million) and a portion of the VAT assessment ($0.06 million). However, the Company has objected to the incorrect imposition of interest on VAT decreasing adjustments on TANESCO payments ($1.1 million) and disallowing input VAT claimed in certain services ($0.1 million). No final assessments have been issued to date with respect to corporation tax, excise duty or payroll tax for 2017 and no preliminary assessment has yet been received for 2018. During 2020, the Company filed an application for judicial review at the CAT with regards to the 2008-10 PAYE case ($0.3 million). During the year, again acting under instructions from the TRA, PAET's commercial bank in Tanzania transferred the full principal tax amount in dispute ($0.3 million) to the TRA. The Company has filed an appeal for review with the CAT.

Management, with the 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.

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Contingencies cont.

Taxation cont.

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 Tax Revenue Appeals Tribunal ("TRAT") and finally to the CAT. Below is a summary of the status of the various assessments:

(1) (a) 2008-10 ($0.3 million): In 2020, the Company lost an appeal with CAT on the principal amount of PAYE tax and filed an application for judicial review at CAT. The TRA instructed PAET's commercial bank to transfer the full principal amount in dispute to TRA;

(2) (a) 2005-2009 ($1.6 million): In 2018 the CAT ruled in favor of the Company that no WHT was required on services performed outside Tanzania by non-resident persons. It is unknown whether TRA will file an application objecting to the CAT ruling;

(3) (a) 2008 ($0.6 million): The Company objected to a TRA assessment that did not recognize a tax loss carried forward and is awaiting a response;

(b) 2009 ($0.8 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 ($1.7 million): The Company is awaiting a hearing at the TRAT following the TRAB ruling in favor of the TRA ($1.7 million);

(d) 2012 ($13.6 million): The Company objected to the TRA assessments with respect to understated revenue, timing of deductibility of capital expenditures, expenses and tax on repatriated income. Following expiry of the statutory deadline for the TRA to respond to its objection, the Company filed an appeal at the TRAB and is awaiting a hearing;

(e) 2013 ($9.3 million): The Company objected to two assessments as being time-barred and without merit ($1.9 million) and tax on repatriated income ($7.4 million) and is awaiting the TRA's response;

(f) 2014 ($8.0 million): The TRA issued two assessments for corporation tax ($4.9 million) and tax on repatriated income ($3.1 million). The Company field objections to the assessments and is awaiting the TRA's response;

(g) 2015-16 ($11.2 million): The TRA issued two assessments for corporation tax ($5.8 million) and tax on repatriated income ($5.4 million). The Company appealed to the TRAB against the assessments following the TRA failure to determine the matters within the statutorily allowed period and is awaiting a response;

(h) 2017-18 ($6.5 million): The TRA issued an assessment for corporation tax including questioning the Company's methodology of grossing up already paid corporation tax ($6.4 million) and raising the issue of imposing interest on deemed delayed payment ($0.1 million). The Company filed an objection and is awaiting the TRA's response;

(4) (a) 2012-16 ($0.2 million): The Company has filed an objection to a TRA assessment with respect to disallowing VAT on certain services and is awaiting a response;

(b) 2017-18 ($1.2 million) The Company has filed an objection to a TRA assessment and is awaiting a response. The Company has objected to incorrect imposition of interest on VAT decreasing adjustments in respect of delayed TANESCO payment ($1.1 million) and disallowing input VAT claimed in certain services ($0.1 million).

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 section 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 (the "IASB") became effective or were amended for financial reporting periods beginning on or after January 1, 2021.

COVID-19 Related Rent Concessions amendment to IFRS 16 has been adopted. There has been no impact on the Company's financial statements or business.

The Interest Rate Benchmark Reform, Phase 2 (Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16). The Company has adopted the amended standards. However, the Company has contracts using US Dollar LIBOR, this rate has yet to be discontinued, and these contracts have yet to transition to an alternative rate. The Company does not expect transitioning to have any material impact on the Company's financial statements.

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

- Onerous contracts – Cost of fulfilling a contract (Amendments to IAS 37).
- Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12).
- Reference to the Conceptual Framework (Amendments to IFRS 3).
- Annual Improvements to IFRS Standards 2018-2020.

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, 2021.

Quarterly Results Summary

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

Figures in $'000 except where otherwise stated	2021				2020			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**24,819**	22,271	20,301	18,631	21,980	20,859	17,320	17,715
Net income attributable to shareholders	**1,548**	7,613	3,246	3,963	7,375	1,487	6,254	12,645
Earnings per share								
– basic and diluted ($)	**0.08**	0.38	0.17	0.18	0.28	0.06	0.27	0.39
Net cash flows from operating activities	**18,521**	12,132	10,251	(794)	19,369	12,793	13,516	827
Capital expenditures	**12,496**	3,715	10,167	232	16,315	9,412	1,005	489

Revenue decreased in the Q2 2020 as a result of increased use of hydropower during an extended rainy season, which led to a fall in sales to the power sector. Revenue increased during Q3 2020 and Q4 2020 as the power sector demand for gas increased to compensate for a reduction in the availability of hydropower. Revenue decreased during Q1 2021 as a result of decreased deliveries to TANESCO and TPDC due to increased availability of hydropower with the onset of the seasonal rains resulting in a decrease in demand for gas power generation. Revenue increased during Q2 2021 as a result of increased sales to the industrial sector and lower TPDC share of revenue as an outcome of increased capital expenditures and higher Cost Gas revenue recoveries by the Company. Revenue increased during Q3 2021 as a result of increased sales to the power sector which was partially offset by increased TPDC share of revenue as an outcome of reduced capital expenditures and lower Cost Gas revenue recoveries by the Company. Revenue increased during Q4 2021 as a result of increased sales to the industrial sector which was partially offset by decreased TPDC share of revenue as a result of increased capital expenditures.

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

- the decrease in Q2 2020 was partially due to lower revenue and a lower collection of TANESCO arrears as compared to Q1 2020;
- the decrease in Q3 2020 was primarily a result of a loss allowance of $5.3 million in respect of the disputed 2008-10 output VAT case with the TRA;
- the increase in Q4 2020 was partially due to the collection of $3.5 million of TANESCO long-term arrears resulting in an increase in the reversal of loss allowances;
- the decrease in Q1 2021 and Q2 2021 was a result of a lower collection of TANESCO arrears as compared to Q4 2020;
- the increase in Q3 2021 was a result of lower general and administrative expenses and lower indirect tax as compared to Q2 2021; and
- the decrease in Q4 2021 was a result of higher general and administrative expenses and higher loss allowance for receivables compared to Q3 2021.

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 2020 was primarily a result of the annual payment of the 2019 current liability associated with APT paid in Q1 2020. The decrease in Q3 2020 resulted from a combination of decreased collections from TANESCO compared to prior periods and a $5.3 million payment to the TRA. Correspondingly, the increase in Q4 2020 resulted from higher collections from TANESCO compared to the previous quarter. The decrease in Q1 2021 and consequent increases in Q2, Q3 and Q4 2021 were mainly a result of the annual 2020 current liability associated with APT paid in Q1 2021.

Capital expenditures in Q1 2020 and Q2 2020 primarily relate to the refrigeration project and flowline decoupling and construction work. Capital expenditures in Q3 2020 and Q4 2020 mainly relate to the installation of compression. Capital expenditures in Q1 2021 were mainly related to well workover planning and design. Capital expenditures in Q2 2021 mainly relate to the installation of compression. Capital expenditures in Q3 and Q4 2021 were mainly related to the well workover program.

Management's Discussion & Analysis cont.

Selected Annual Financial Information

Selected annual financial information derived from the audited consolidated financial statements for the years ended December 31, 2021, 2020 and 2019 is set out below:

Figures in $'000 except per share amount	2021	2020	2019
Revenue	**86,022**	77,874	85,595
Net income attributable to shareholders	**16,370**	27,761	24,718
Earnings – basic and diluted ($ per share)	**0.81**	1.00	0.71
Cash dividends declared (CDN$ per Class A and B Shares)	**0.40**	0.28	0.23
Net cash flows from operating activities	**40,110**	46,505	34,873
Total non-current liabilities	**95,744**	98,008	102,603
Total assets	**230,271**	242,612	271,772

Revenue decreased by 9% in 2020 compared to 2019 primarily due to lower power sales volumes and a lower current income tax adjustment. The 10% increase of revenue in 2021 compared to 2020 was a result of increased sales to TANESCO, TPDC and industrial customers as well as a higher current income tax adjustment.

The increase in net income attributable to shareholders in 2020 was primarily due to increased reversal of loss allowances related to the collection of TANESCO arrears. The decrease in net income attributable to shareholders in 2021 was primarily a result of decreased reversal of loss allowances related to the collection of TANESCO arrears.

In 2019 the Company approved quarterly dividends, CDN$0.05 per share for Q1 and CDN$0.06 per share for Q2, Q3 and Q4. In 2020 the Company approved quarterly dividends, CDN$0.06 per share for Q1 and Q2 and CDN$0.08 per share for Q3 and Q4. In 2021 the Company approved quarterly dividends, CDN$0.10 per share for Q1, Q2, Q3 and Q4. Please refer to the table in the Substantial Issuer Bid, 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 and in trade and other receivables.

Total non-current liabilities did not change significantly between the years. The $4.6 million decrease in 2020 compared to 2019 and the $2.3 million decrease in 2021 compared to 2020 were primarily a result of the repayment of a portion of the APT and the reclassification of $5.0 million of the IFC loan as a current liability in 2021.

Total assets decreased by 11% in 2020 compared to 2019 and 5% in 2021 compared to 2020. These decreases were mainly a result of the 2020 SIB and 2021 SIB, respectively. Please refer to the Substantial Issuer Bid, Normal Course Issuer Bid and Dividends section of this MD&A.

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 and net cash flows from operating activities per share.

These non-GAAP financial measures and ratios disclosed in this MD&A do not have any standardized meaning under 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 and Ratios cont.

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	2021	2020	2021	2020
Pipelines, well workovers and infrastructure	**(12,494)**	(16,310)	**(26,596)**	(27,117)
Other capital expenditures	**(2)**	(5)	**(14)**	(24)
Capital expenditures	**(12,496)**	(16,315)	**(26,610)**	(27,141)
Change in non-cash working capital	**(1,133)**	192	**1,625**	105
Proceeds from sale of investments in bonds, net	**–**	44,756	**–**	44,756
Net cash (used by) from investing activities	**(13,629)**	28,633	**(24,985)**	17,720

Operating netback

Operating netback is calculated as revenue less processing and transportation tariffs, TPDC's revenue share, and operating and distribution costs (see "Operating Netback"). The operating netback summarizes all costs that are associated with bringing the gas from the Songo Songo Gas field to the market, it 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	2021	2020	2021	2020
Revenue	**24,819**	21,980	**86,022**	77,874
Production, distribution and transportation expenses	**(3,256)**	(3,520)	**(12,253)**	(11,904)
Net Production Revenue	**21,563**	18,460	**73,769**	65,970
Less current income tax adjustment (recorded in revenue)	**(1,416)**	134	**(8,385)**	(5,807)
Operating net back	**20,147**	18,594	**65,384**	60,163
Sales volumes MMcf	**6,539**	5,777	**22,312**	21,117
Netback $/mcf	**3.08**	3.22	**2.93**	2.85

Non-GAAP Ratios

Operating netback per mcf

Operating netback per mcf represent 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.

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.

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, 2021 audited consolidated financial statements for a description of estimates and judgments.

Management's Discussion & Analysis cont.

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.

COVID-19

The emergence of COVID-19 resulted in travel bans, mandatory and self-imposed quarantines and isolations, social distancing and the closing of non-essential businesses which has had a negative impact on economies world-wide. The Company originally took appropriate action to protect employees such as social distancing, working from home where possible and ensuring staff who work on rotation at our operational site on Songo Songo Island are tested for COVID-19, and placed into quarantine prior to receiving their results and before resuming regular duties. The Company has since returned to office based working but continues to observe social distancing wherever possible. Staff traveling to Songo Songo Island are now subject to lateral flow testing and may only travel if the result is negative. The Company's business, operations and financial condition have not been significantly adversely affected by COVID-19, however there has been a decline in revenue from gas deliveries as a result of temporary business slowdowns, closures and expansion delays. Although the Company has lived with the impact of COVID-19 for almost two years, the full extent of the risks surrounding the long-term impact and severity of the COVID-19 pandemic remains unclear at this time. The further spread of COVID-19 could result in volatility and disruptions in regular business operations including disruption of supply chains that could impact operations and performance of counter-parties, volatility in foreign exchange rates, payment delays from customers, additional cyber-security and internal control risk as a result of more employees working remotely as well as declining trade and market sentiment. COVID-19 poses a risk on the financial capacity of the Company's contract counterparties and potentially their ability to perform contractual obligations and the Company's ability to implement planned capital projects. Although the Company's production and reserves are entirely comprised of natural gas, a prolonged decline in world oil prices could impact the competitiveness and demand for natural gas in Tanzania and negatively impact Company revenues, collectability of receivables and cash flow.

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.

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.

Business Risks cont.

Industry and Business Conditions cont.

Effects of climate change cont.

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 (including the Glasgow Climate Pact, which was recently signed by nearly 200 countries), 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 and pricing

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, which now includes the NNGI. 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. 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 few years 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.

Financial

Cost of capital

Our 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 two years relating to revenue.

Business Risks cont.

Industry and Business Conditions cont.

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, British pounds sterling, Euros 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 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 at any given time. To mitigate the risk of Tanzanian shilling devaluation, the Company regularly converts Tanzanian shilling receipts into US dollars 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.

Fluctuations in currency exchange rates could adversely impact the Company's financial results.

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, the Company's subsidiary operating in Tanzania currently has a long-term 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.

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.

Business Risks cont.

Foreign operations and concentration risk cont.

Country risk

The geographic location of the Songo Songo license 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, creeping 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 awarding 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 are susceptible to outbreaks of disease and may lack the resources to effectively contain such an outbreak quickly. Such outbreaks may impact our ability to explore for natural gas, develop or produce our license areas by limiting access to qualified personnel, 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 there, 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 2021 Transparency International Corruption Index (2020: 94 out of 180). Having assessed the Company's exposure to corruption in Tanzania, it has been concluded that the risk 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

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 (the Petroleum Upstream Regulatory Authority ("PURA") and the Energy and Water Utilities Regulatory Authority ("EWURA")), and TPDC. Under the terms of the Gas Agreement (as defined below) 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, then 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").

Business Risks cont.

Contractual, regulatory and legislation risk cont.

Contracts and regulations cont.

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 annual work programs must be submitted 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 five 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 Written Laws (Miscellaneous Amendments) Act, 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 (the "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.

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 not notify the Company within 90 days of notice from the Company that the MoE has approved the Additional Gas Plan, then TPDC is deemed not to have elected 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, 2021, 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.

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 50MMcfd on occasion, increasing average sales volumes and revenues.

Principal Terms of the PSA and Related Agreements cont.

Revenue Sharing Terms and Taxation cont.

(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) "Additional Profits Tax" (or "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 United States Industrial Goods Producer Price Index ("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) 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 ("Gas Agreement"), 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 (257 Bcf as at December 31, 2021). The Company did not have a shortfall during the reporting period and does not anticipate a shortfall arising during the term of the Protected Gas delivery obligation to July 2024.

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 (the pipeline and delivery pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-Rating Agreement, the Company 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 maximum daily quantity which PAET and TPDC approved effective January 29, 2018. The seller is now obligated, subject to infrastructure capacity, to sell a maximum of approximately 26 MMcfd (previously 36 MMcfd) for use in any of TANESCO's current power plants, except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately $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 and $3.20/mcf on July 1, 2021.

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 maximum daily quantity 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. All volumes above 20 MMcfd are supplied on a best endeavors basis until compression facilities are added to the Songas Infrastructure.

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.

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 ability for the SS-4 well to flow naturally following the installation of a coiled nitrogen unit; the timing of when the coiled nitrogen unit and other equipment will be on location; the demand for gas and Orca's average gross gas sales are in line with the Company's forecasts; the results of discussions with the MoE, TPDC and TANESCO relating to the increase in gas supply; the timing for when new power generation facilities are commissioned; the amount of debt and interest payments and capital expenditures are in line with the Company's forecasts; the Company's expectations regarding supply and demand of natural gas; the Company's expectations regarding timing and cost for the completion of installation of compression on the Songas Infrastructure and the well workover program; the Company's expectations as to the efficacy of the compression and its ability to sustain gas production at existing levels to the end of our license; anticipated production volumes and increased well deliverability as a result of the installation of compression on the Songas Infrastructure and the completion of the well workover program; the Company's expectations regarding timing and cost for the completion of the 3D seismic acquisition program; the results of negotiations with Orca's preferred service provider to conduct the 3D seismic acquisition program; the ability for the Company to obtain environmental approvals and the availability of suitable weather windows to conduct the 3D seismic acquisition program; current and potential production capacity of the Songo Songo gas field; the receipt of the payment of arrears from TANESCO; the Company's expectation that there will continue to be no restrictions on the movement of cash from Jersey, Mauritius or Tanzania; expected timing, cost and ability to remediate one onshore well, SS-4; the Company's expectation that it will not incur any losses from debtors; the Company's expectation that all planned capital expenditures be funded out of existing working capital and cash flow generated by current operations; the timing and effective rate of the APT payable by the Company; the Company's ability to produce additional volumes; the Company's expectation that it can expand and maintain the deliverability of gas volumes in excess of the existing Songas Infrastructure; the potential impact on the Company resulting from the further spread of COVID-19; the Company's expectations regarding the impact on operations resulting from the GoT's new restrictions in response to COVID-19; 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; expectations in respect of its appeals on the decisions of the TRAB, TRAT and CAT and other statements under "Contingencies – Taxation"; the Company's expectations that the IASB pronouncements will not have any impact on the Company's consolidated financial statements; the availability of additional debt financing; the ability of the Company to compete with other companies in the industry; the Company's ability to access appropriate equipment and infrastructure in a timely manner; the Company's ability to respond to changing technological developments; the Company's ability to attract and retain key personnel; the timing and effect of additional reporting requirements as a result of new environmental and climate-change related legislation; the ability of third parties who contract with the Company to meet their obligations; and the Company's ability to maintain positive commercial relationships with the GoT and other state and parastatal organizations. 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: failure to receive payments from TANESCO; risks related to the implementation of potential financing solutions to resolve the TANESCO arrears; risk that the well workovers are unsuccessful or determined to be unfeasible; 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; risk that the Company may be unable to develop additional supply or increase production values; risks associated with the Company's ability to complete sales of Additional Gas; potential negative effect on the Company's rights under the PSA and other agreements relating to its business in Tanzania as a result of the Petroleum Act, 2015 and other 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; risks regarding the uncertainty around evolution of Tanzanian legislation; risk that the Company will not be successful in appealing claims made by the TRA and may be required to pay additional taxes and penalties; the impact of general economic conditions in the areas in which the Company operates; civil unrest; the susceptibility of the areas in which the Company operates to outbreaks of disease; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations, impact of local content regulations and variances in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility; competition for, among other things, capital, oil and gas field services and skilled personnel; failure to obtain required equipment for field development; delays in development plans; failure to obtain expected results from the drilling or workover of wells; 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; changes in laws; imprecision in reserve estimates; the production and growth potential of the Company's assets; obtaining required approvals of regulatory authorities; failure to install compression on the Songas Infrastructure or complete the well workover program and 3D seismic acquisition program on the timelines or at the costs anticipated; risks associated with negotiating with foreign governments; inability to satisfy debt conditions of financing; failure to successfully

Forward-Looking Statements cont.

negotiate agreements; risk that the Company will not be able to fulfill its contractual obligations; reduced global economic activity as a result of COVID-19, including lower demand for natural gas and a reduction in the price of natural gas; the potential impact of COVID-19 on the health of the Company's employees, contractors, suppliers, customers and other partners and the risk that the Company and/or such persons are or may be restricted or prevented (as a result of quarantines, closures or otherwise) from conducting business activities for undetermined periods of time; and the impact of actions taken by governments to reduce the spread of COVID-19, including declaring states of emergency, imposing quarantines, border closures, temporary business closures for companies and industries deemed non-essential, significant travel restrictions and mandated social distancing, and the effect on the Company's operations, access to customers and suppliers, availability of employees and other resources; 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, the ability of the Company to negotiate Additional Gas sales contracts; the ability of the Company to complete additional developments and increase its production capacity; the actual costs to complete the Company's workover program, the installation of compression and the 3D seismic acquisition program are in line with estimates; that there will continue to be no restrictions on the movement of cash from Mauritius, Jersey or Tanzania; the impact of COVID-19 on the demand for and price of natural gas, volatility in financial markets, disruptions to global supply chains and the Company's business, operations, access to customers and suppliers, availability of employees to carry out day-to-day operations, and other resources; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company will 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; future capital expenditures; availability of skilled labor; timing and amount of capital expenditures; uninterrupted access to infrastructure; the impact of increasing competition; conditions in general economic and financial markets; effects of regulation by governmental agencies; that the Company'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 new environmental and climate-change related regulations will not negatively impact the Company; the Company is able 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; the IASB pronouncements will not have any impact on the Company's consolidated financial statements; the new power generation facilities are commissioned on the expected timelines; 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.sedar.com.

Glossary

mcf	Thousand standard cubic feet
MMcf	Million standard cubic feet
Bcf	Billion standard cubic feet
Tcf	Trillion 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