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, 2020. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON APRIL 21, 2021. ALL AMOUNTS ARE REPORTED IN US DOLLARS ("$") UNLESS OTHERWISE NOTED.

THIS MD&A CONTAINS NON-GAAP MEASURES 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 MEASURES", "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 Production 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"). 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. The Company receives no revenue for the Protected Gas delivered to Songas 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 for 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 and a more cost-effective alternative to liquid fuels. The Company currently supplies Additional Gas directly to TANESCO by way of the Portfolio Gas Supply Agreement ("PGSA") between the Company, TANESCO and TPDC and indirectly through the supply of Protected Gas and Additional Gas to Songas, which in turn generates and sells power to TANESCO. Subject to meteorological conditions and increased use of hydropower generation, the gas the Company currently supplies to Songas and TANESCO via the Songas Infrastructure and the National Natural Gas Infrastructure ("NNGI"), generates approximately 40% of the electrical power and approximately 66% of the gas utilized for power generation in Tanzania.

In 2019 the Company entered into a long-term gas sales agreement ("LTGSA") with TPDC to supply up to 30 million standard cubic feet per day ("MMcfd") of gas through the NNGI. Prior to signing the LTGSA the processing and distribution of natural gas volumes had been restricted by infrastructure limitations at the Songas Infrastructure.

In addition to supplying gas to TPDC, Songas and TANESCO, the Company has developed 49 contracts to supply gas to Dar es Salaam's industrial market.

Outlook - COVID-19

In the year ended December 31, 2020 global oil prices declined significantly as a result of reduced demand driven by the ongoing coronavirus pandemic ("COVID-19") and concerns of excess supply resulting from failed negotiations between OPEC and other countries. As of now, there remains a considerable uncertainty regarding the duration and extent of oil demand destruction as a result of COVID-19. Although the Company's production and reserves are entirely comprised of gas, the current challenging economic climate has the potential to have significant adverse impacts on the Company, including, but not limited to:

- potential material declines in revenue and cash flows due to reduced commodity prices,
- potential declines in future revenue, which could result in increased impairment charges on long-term assets,
- potential increased risk of non-performance by the Company's customers which could materially increase collection risk of accounts receivable and customer defaults on contracts,
- potential increased risk of non-performance by the Company's suppliers impacting timing for delivery of equipment and supplies delaying implementation of key projects,
- potential prolonged demand reduction which could negatively impact the Company's ability to maintain liquidity, and
- potential impact on overall operating results and financial position.

There has been a decrease in industrial sales but no significant impact on the Company's operations to date due to COVID-19 however the current situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company are not known at this time. The Company has taken precautions including testing for COVID-19 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.

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, 2020

(Expressed in $'000 unless indicated otherwise)	Three Months ended December 31 2020	Three Months ended December 31 2019	% Change Q4/20 vs Q4/19	Year ended December 31 2020	Year ended December 31 2019	% Change Ytd/20 vs Ytd/19
OPERATING						
Daily average gas delivered and sold *(MMcfd)*	**62.8**	70.8	(11)%	**57.7**	63.1	(9)%
Industrial	**12.4**	13.1	(5)%	**12.7**	13.3	(5)%
Power	**50.4**	57.7	(13)%	**45.0**	49.8	(10)%
Average price *($/mcf)*						
Industrial	**7.56**	7.77	(3)%	**7.44**	7.97	(7)%
Power	**3.52**	3.44	2%	**3.47**	3.43	1%
Weighted average	**4.32**	4.24	2%	**4.34**	4.38	(1)%
Operating netback *($/mcf)*[1]	**3.22**	2.73	18%	**2.85**	2.63	8%
FINANCIAL						
Revenue	**21,980**	23,212	(5)%	**77,874**	85,595	(9)%
Net income attributable to shareholders	**7,375**	12,642	(42)%	**27,761**	24,718	12%
per share – basic and diluted *($)*	**0.28**	0.37	(24)%	**1.00**	0.71	41%
Net cash flows from operating activities	**19,369**	5,051	283%	**46,505**	34,873	33%
per share – basic and diluted *($)*	**0.74**	0.15	393%	**1.67**	1.00	67%
Adjusted funds flow from operations[1]	**12,348**	13,479	(8)%	**39,144**	43,213	(9)%
per share – basic and diluted *($)*	**0.47**	0.39	21%	**1.41**	1.24	14%
Capital expenditures	**16,315**	1,014	1,509%	**27,141**	4,171	551%
Weighted average Class A and Class B shares *('000)*	**26,138**	34,324	(24)%	**27,818**	34,931	(20)%

	As at December 31, 2020	As at December 31, 2019	% Change
Working capital (including cash)	**74,236**	106,972	(31)%
Cash and cash equivalents	**104,190**	93,899	11%
Investments in short-term bonds	**–**	44,756	(100)%
Long-term loan	**54,246**	54,057	0%
Outstanding shares *('000)*			
Class A	**1,750**	1,750	0%
Class B	**24,388**	32,557	(25)%
Total shares outstanding	**26,138**	34,307	(24)%
RESERVES[2]			
Gross Reserves *(Bcf)*			
Proved	**203**	234	(13)%
Probable	**27**	31	(13)%
Proved plus probable	**230**	265	(13)%
Net Present Value, discounted at 10% *($ million)*[3]			
Proved	**216**	237	(9)%
Proved plus probable	**241**	283	(15)%

1 Please refer to Non-GAAP measures section of the MD&A for additional Information.

2 Please refer to 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 continued

Financial and Operating Highlights for 2020 and Q4 2020

- On August 3, 2020 the Company signed a $38 million contract for installation of compression on the Songas gas processing facility which is part of the Songas Infrastructure ("Compression Contract"). To date $24.7 million has been spent. Compression is currently planned for installation prior to the end of Q2 2022 and will allow maximum production volumes of approximately 102 MMcfd to be sustained through the Songas Infrastructure, with the possibility to expand well deliverability to 172 MMcfd by also increasing the amount of gas currently being delivered through the NNGI. The forecasted expenditures under this contract are $9.5 million in 2021, upon delivery and inspection of the equipment, and a further $3.8 million in 2022 following completion of installation and testing.
- During 2020 the Company announced its intention to focus on maximizing value and shareholder returns through the optimization and monetization of the Company's rights to develop the Songo Songo gas field in Tanzania and to suspend efforts to acquire and develop an integrated gas business in other African countries. In November 2020 the Board of Directors approved a Dividend and Distribution Policy targeting regular quarterly dividends to align with our core strategy of providing meaningful returns to our shareholders while focusing on expanding our gas business to participate in the growth of the Tanzanian domestic gas markets.
- Revenue decreased by 5% for Q4 2020 and by 9% for the year compared to the same prior year periods. The decreases are primarily a result of decreased sales to TANESCO under the PGSA and a smaller current income tax adjustment due to increased capital expenditure and lower gross field revenue. Gas deliveries decreased by 11% for Q4 2020 and by 9% for the year compared to the same prior year periods. The decrease in revenue and gas delivery volumes for the year were primarily due to the increase in hydropower generated during the first eight months of the year as a result of higher than normal rainfall in 2020 compared to the prior year. The decrease in gas volumes in Q4 2020 is primarily the result of lower nominations of gas volumes by TANESCO and TPDC through the NNGI compared to Q4 2019 as volumes delivered in Q4 2019 were the highest for any single quarter since production started in 2004. The decrease in volumes for Q4 2020 was partially offset by a 2% increase in the weighted average price of gas sold compared to Q4 2019.
- Net income attributable to shareholders decreased 42% for Q4 2020 and increased by 12% for the year compared to the same prior year periods. The decrease for Q4 2020 was primarily a consequence of the decrease in revenue and a decrease in the reversal of loss allowances related to the lower collection of arrears from TANESCO compared to Q4 2019. The increase in net income attributable to shareholders for the year was primarily the result of the increase in the reversal of loss allowances of $8.2 million mainly due to increased collection of TANESCO arrears during the first nine months of 2020 and was also positively impacted by savings in general and administrative expenses and stock based compensation. The increase for the year was partially offset by the impairment of receivable as a result of the Tanzania Revenue Authority ("TRA") issuing an Agency Notice during the year obligating the Company's bank to release $5.3 million in favor of the TRA.
- Net cash flows from operating activities increased 283% for Q4 2020 and by 33% for the year compared to the same prior year periods. The increases are primarily a result of the collection of TANESCO arrears and changes in non-cash operating working capital associated with decreases in prepayments and in trade and other receivables.
- Adjusted funds flow from operations decreased by 8% for Q4 2020 and by 9% for the year compared to the same prior year periods. The decreases are primarily a result of the decreases in revenue.
- Capital expenditures increased by 1,509% for Q4 2020 and by 551% for the year over the comparable prior year periods. The capital expenditures in 2020 primarily relate to the flowline decoupling construction and payments under the Compression Contract. The capital expenditures in 2019 primarily relate to the refrigeration project for the Songas Infrastructure.
- The Company exited the period in a strong financial position with $74.2 million in working capital (December 31, 2019: $107.0 million), cash and cash equivalents of $104.2 million (December 31, 2019: $93.9 million), short-term investments of $ nil (December 31 ,2019: $44.8 million) and long-term debt of $54.2 million (December 31, 2019: $54.1 million). The decrease in working capital and short-term investments was primarily related to the substantial issuer bid ("2020 SIB") completed in March 2020.
- Total proved conventional natural gas reserves ("1P") and total proved plus probable conventional natural gas reserves ("2P") decreased 13% at December 31, 2020 compared to the prior year. The decrease is due to gross property Additional Gas production in 2020 of 21.1 Bcf (2019: 23.1 Bcf) and lower forecasted sales over the remaining life of the Songo Songo license. The net present value of estimated future cash flows from 2P reserves at a 10% discount rate decreased by 15% 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 70.9 MMcfd for 2021 compared to actual results of 62.8 MMcfd for Q4-2020. 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, 2020 the current receivable from TANESCO was $ nil (December 31, 2019: $ nil). TANESCO's long-term trade receivable as at December 31, 2020 was $27.6 million with a provision of $27.6million compared to $47.5 million (provision of $47.5 million) as at December 31, 2019. Subsequent to December 31, 2020 the Company has invoiced TANESCO $6.5 million for 2021 gas deliveries and TANESCO has paid the Company $7.9 million. TANESCO also paid the take or pay invoice of $5.0 million for the 2015-2016 contract year for gas to be taken by June 30, 2021.
- On February 25, 2020 and June 22, 2020 the Company declared dividends of CDN$0.06 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 $2.5 million to the holders of record as of March 31, 2020 and June 30, 2020 (paid on April 30, 2020 and July 15, 2020 respectively). On September 17, 2020 and November 19, 2020 the Company declared a dividend of CDN$0.08 per share on each of its Class A Shares and Class B Shares for a total of $3.2 million to the holders of record as of September 30, 2020 and December 31, 2020 (paid on October 15, 2020 and January 15, 2021 respectively).

Financial and Operating Highlights for 2020 and Q4 2020 continued

- On March 12, 2020 the Company announced the final results of the 2020 SIB where the Company repurchased and canceled 7,692,297 Class B Shares at CDN$6.50 per Class B Share. The aggregate purchase of Class B Shares totaled CDN$50.0 million representing 23.6% of Orca's issued and outstanding Class B Shares and 22.4% of the total number of Orca's issued and outstanding shares.
- On April 6, 2020 Orca received approval from the TSX Venture Exchange ("TSXV") to amend its normal course issuer bid ("NCIB") commenced on June 14, 2019 to allow it to purchase additional Class B Shares through the facilities of the TSXV and alternative trading systems in Canada. On June 19, 2020 Orca announced the completion of the NCIB under which Orca repurchased 477,500 Class B Shares at a weighted average price of CDN$5.32 per Class B Share for aggregate consideration of approximately CDN$2.5 million.
- On December 14, 2020 the Company announced commencement of another substantial issuer bid ("2021 SIB") at a price of not less than CDN$6.50 and not more than CDN$7.50 per Class B Share. On January 22, 2021 the Company announced the final results of the substantial issuer bid whereby the Company repurchased and canceled 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 February 23, 2021 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, 2021 paid on April 15, 2021.

Oil and Gas Advisory

The Company's conventional natural gas reserves as at December 31, 2020 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, 2020 and December 31, 2019 and preparation date of February 23, 2021 and February 20, 2020 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, 2020 and December 31, 2019, 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 percent 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 (6Mcf: 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.

Management's Discussion & Analysis continued

Operating Volumes

The average gross daily sales volume decreased by 11% for Q4 2020 and by 9% for the year compared to the same prior year periods. The decrease in gross sales volume was primarily due to decreased sales of natural gas to TANESCO partially offset by increased sales to TPDC for the year through the NNGI.

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	
	2020	2019	2020	2019
Gross sales volume *(MMcf)*				
Industrial sector	**1,137**	1,206	**4,633**	4,836
Power sector	**4,640**	5,309	**16,484**	18,183
Total volumes	**5,777**	6,515	**21,117**	23,019
Gross daily sales volume average *(MMcfd)*				
Industrial sector	**12.4**	13.1	**12.7**	13.3
Power sector	**50.4**	57.7	**45.0**	49.8
Gross daily sales volume average total	**62.8**	70.8	**57.7**	63.1

Industrial Sector

There was a decrease of 5% in industrial sales volumes for Q4 2020 and for the year over the comparable prior year periods. The decrease was primarily due to the reduction in demand for services and products, including natural gas as a consequence of the COVID-19 pandemic. This was partially offset by an increase in the number of industrial customer contracts entered into during the year.

Power Sector

Power sector sales volumes decreased by 13% for Q4 2020 and 10% for the year over the comparable prior year period. The decrease was primarily due to decreased gas sales to TANESCO partially offset by increased sales to TPDC though the NNGI for the year.

Protected Gas Volumes

Protected Gas volumes decreased by 10% to 3,335 MMcf (36.3 MMcfd) for Q4 2020 compared to 3,693 MMcf (40.1 MMcfd) for Q4 2019 and decreased by 17% to 12,138 MMcf (33.2 MMcfd) for the year compared to 14,571 MMcf (39.9 MMcfd) for the year ended December 31, 2019. 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	2020	2019	2020	2019
Average sales price				
Industrial sector	**7.56**	7.77	**7.44**	7.97
Power sector	**3.52**	3.44	**3.47**	3.43
Weighted average price	**4.32**	4.24	**4.34**	4.38

Industrial Sector

The average Industrial sector sales price decreased by 3% for Q4 2020 and by 7% for the year compared to the same prior year periods. The decrease in prices is primarily due to the underlying decrease in the price of heavy fuel oil against which most of the industrial customer contracts are priced. As well, a reset of the caps and floors in the majority of industrial contracts also reduced prices compared to the prior year periods. The caps and floors were reduced to ensure gas remained competitive against alternate fuel sources and other suppliers.

Power Sector

The average Power sector sales price increased by 2% for Q4 2020 and by 1% for the year over the comparable prior year periods. The increase is due to price indexing embedded into the sales contracts.

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 average Additional Gas sales volumes for the quarter and the year ended December 31, 2020 and for the comparable prior year periods were above 50 MMcfd entitling the Company to a 55% share of Profit Gas revenue. The Company was allocated a total of 88% of the net field revenue for the quarter ended December 31, 2020 (Q4 2019: 75%) and 77% for the year ended December 31, 2020 (year ended December 31, 2019: 69%). The increase in allocation reflects the increase in Cost Gas revenue primarily a result of the increase in capital expenditures during the year and the resulting recovery of a percentage of these expenditures.

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

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

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Industrial sector	**8,589**	9,374	**34,485**	38,530
Power sector	**16,347**	18,245	**57,267**	62,329
Gross field revenue	**24,936**	27,619	**91,752**	100,859
TPDC share of revenue	**(2,822)**	(6,347)	**(19,685)**	(28,334)
Company operating revenue	**22,114**	21,272	**72,067**	72,525
Current income tax adjustment	**(134)**	1,940	**5,807**	13,070
	21,980	23,212	**77,874**	85,595

Revenue decreased by 5% for Q4 2020 and by 9% for the year compared to the same prior year periods. The decrease is largely a consequence of decreased sales to TANESCO under the PGSA and smaller current income tax adjustments.

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	2020	2019	2020	2019
Operating costs	**844**	361	**2,539**	1,310
Tariff for processing and pipeline infrastructure	**2,056**	2,576	**7,009**	8,404
Ring-main distribution costs	**620**	542	**2,356**	2,151
	3,520	3,479	**11,904**	11,865

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 sales during the period. Operating costs increased by 134% for Q4 2020 and by 94% for the year compared to the same prior year periods. The increase is due to increased expenditure on reserve and resource evaluation and the introduction of a new tariff by the Tanzanian Petroleum Upstream Regulatory Authority ("PURA") in Q4 2019. Tariff for processing and pipeline infrastructure decreased by 20% for Q4 2020 and by 17% for the year compared to the same prior year periods primarily as result of reduced gas volumes processed and delivered during the periods. Ring-main distribution costs increased by 14% for Q4 2020 and by 10% for the year compared to the same prior year periods primarily a result of increased costs to maintain the ring-main.

Management's Discussion & Analysis continued

Operating Netbacks

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

	Three Months ended December 31		Year ended December 31	
$/mcf	2020	2019	2020	2019
Gas price – Industrial	**7.56**	7.77	**7.44**	7.97
Gas price – Power	**3.52**	3.44	**3.47**	3.43
Weighted average price for gas	**4.32**	4.24	**4.34**	4.38
TPDC Profit Gas entitlement	**(0.49)**	(0.97)	**(0.93)**	(1.23)
Production, distribution and transportation expenses	**(0.61)**	(0.54)	**(0.56)**	(0.52)
Operating netback	**3.22**	2.73	**2.85**	2.63

The operating netback increased by 18% for Q4 2020 and by 8% for the year over the comparable prior year periods. The increase is mainly due to a lower TPDC Profit Gas entitlement as a consequence of higher capital expenditures increasing Cost Gas revenue which reduced the available Profit Gas.

General and Administrative Expenses

General and administrative expenses are detailed in the tables below:

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Employee and related costs	**1,600**	1,409	**7,499**	6,188
Office costs	**1,206**	1,052	**4,006**	4,438
Marketing and business development costs	**130**	536	**879**	1,921
Reporting, regulatory and corporate	**191**	561	**1,208**	1,850
	3,127	3,558	**13,592**	14,397

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 our operations in Tanzania and are cost recoverable under the PSA.

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Tanzania	**2,184**	2,176	**7,052**	8,214
Corporate	**943**	1,382	**6,540**	6,183
	3,127	3,558	**13,592**	14,397

General and administrative expenses averaged $1.0 million per month during Q4 2020 (Q4 2019: $1.2 million) and $1.1 million per month over the year (2019: $1.2 million). The 21% increase in employee and related costs in 2020 was mainly due to termination settlements the Company agreed to with the former CEO, and with employees who had worked on business development, following the decision to focus on Tanzanian operations and to suspend plans for expansion to other countries in Africa. Correspondingly, there was a 10% decrease in office costs and a 54% decrease in marketing and business development costs during the year. The reporting, regulatory and corporate costs in 2020 were 35% lower than in 2019, primarily because of the higher level of costs incurred in the strategic review work that was undertaken in the latter part of 2019.

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	2020	2019	2020	2019
Stock appreciation rights ("SARs")	**681**	559	**671**	2,015
Restricted stock units ("RSUs")	**146**	155	**403**	440
	827	714	**1,074**	2,455

As at December 31, 2020 a total of 1,242,166 SARs were outstanding compared to 2,321,833 SARs as at December 31, 2019. A total of 160,000 new SARs were issued during the year ended December 31, 2020 with an exercise price of CDN$5.02. A total of 697,000 SARs with exercise prices ranging from CDN$2.30 to CDN$5.00 were exercised during the year ended December 31, 2020 resulting in a total cash payout of $0.6 million. A total of 542,667 SARs with exercise prices ranging from CDN$5.00 to CDN$6.65 were forfeited during the year ended December 31, 2020.

As at December 31, 2020 a total of 133,200 RSUs were outstanding compared to 234,700 at December 31, 2019. A total of 20,500 new RSUs were issued during the year ended December 31, 2020 with an exercise price of CDN$0.01. A total of 78,000 RSUs were exercised during the year ended December 31, 2020 resulting in a total cash payout of $0.3 million. A total of 44,000 RSUs with an exercise price of CDN$0.01 were forfeited during the year.

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 payables. 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 31.0% to 41.0%, 5% forfeiture and a closing price of CDN$6.33 per Class B Share. The valuation of the SARs and RSUs awards is increased to reflect the amount of dividends paid between the award date to the time of exercise.

As at December 31, 2020 a total accrued liability of $2.2 million (December 31, 2019: $2.5 million) has been recognized in relation to SARs and RSUs. The Company recognized an expense for the year of $1.1 million (2019: $2.5 million) as stock based compensation.

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, 2020 the estimated proved reserves remaining to be produced over the term of the PSA license were 203 Bcf (December 31, 2019: 234 Bcf). The average depletion rate was $0.69/mcf for the year ended December 31, 2020 compared to $0.63/mcf for the comparable prior year.

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Oil and natural gas interests	**4,078**	4,566	**14,830**	15,005
Office and other	**11**	30	**94**	135
Right-of-use assets	**73**	47	**397**	189
	4,162	4,643	**15,321**	15,329

The depletion for oil and natural gas interests decreased by 11% for Q4 2020 and by 1% for the year compared to the same prior year periods. The decrease is primarily a result of the decrease in volume of gas produced and sold partially offset by the increase in the average depletion rate between periods.

Management's Discussion & Analysis continued

Finance Income and Expense

Finance income is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Interest income	**124**	237	**844**	666
Investment income	**–**	416	**305**	2,199
	124	653	**1,149**	2,865

At December 31, 2020 the Company did not have investments in short-term bonds (December 31, 2019: $44.8 million invested with maturity dates from February 2020 to July 2020 at a range of interest rates from 1.375% to 2.75%). The $0.3 million investment income for the year (2019: $2.2 million) includes interest earned of $0.3 million (2019: $1.4 million) and amortization of the discount on the acquisition of the bonds of $ nil (2019: $0.8 million). The investment income for Q4 2019 included accrued interest of $0.3 million and amortization of the discount on the acquisition of the bonds of $0.1 million.

Finance expense is detailed in the table below:

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Base interest expense	**1,467**	1,481	**5,830**	6,164
Participation interest expense	**889**	120	**1,971**	2,071
Lease interest expense	**14**	20	**86**	44
Interest expense	**2,370**	1,621	**7,887**	8,279
Net foreign exchange loss (gain)	**58**	9	**(438)**	289
Indirect tax	**203**	303	**1,873**	1,298
	2,631	1,933	**9,322**	9,866

The base interest expense decrease for the year is a result of the long-term loan repayment of $4.8 million made during Q4 2019. Base and participation interest expense relate to the $60 million long-term loan ("Loan") from the International Finance Corporation ("IFC") to the Company's subsidary operating in Tanzania, PanAfrican Energy Tanzania Limited ("PAET"). Base interest on the Loan is payable quarterly 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 interest expense is payable quarterly in arrears. The participation interest expense is paid annually in arrears. It equates to 6.4% of PAET's net cash flows from operating activities net of 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.

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 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. The increase in indirect taxation is primarily the result of a 2020 take or pay invoice of $6.5 million; in 2019 no take or pay invoice was issued as TANESCO took the required volumes during the contract year to June 20, 2019. These invoices are not recognized in the financial statements as they do not meet revenue recognition criteria with respect to assurance of collectability.

Loss Allowance for Receivables

$'000	Three Months ended December 31 2020	Three Months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Reversal of loss allowance	**(3,478)**	(7,546)	**(20,951)**	(11,044)
Loss allowance	**–**	–	**5,337**	–
	(3,478)	(7,546)	**(15,614)**	(11,044)

The reversal of the loss allowance of $21.0 million during the year (2019: $11.0 million) includes collection of: (i) TANESCO arrears of $19.9 million (2019: $11.0 million) which had previously been allowed for and represents the excess of receipts over gas sales invoiced during the year; and (ii) Songas arrears of $1.1 million (2019: $ nil) which had previously been allowed for. The reversal of the loss allowance of $3.5 million during the quarter (Q4 2019: $7.5 million) relates to the collection of TANESCO arrears which had been previously allowed for and represents the excess of receipts over gas sales invoiced during the quarter.

The loss allowance is a result of the TRA issuing an Agency Notice during the year obligating the Company's bank to release $5.3 million in favor of the TRA. The subject of the notice is an ongoing dispute which, based on the opinion of the Company's legal advisors, has a better than a 50% chance of being resolved in favor of the Company. The Company has therefore recorded the $5.3 million in other receivables, but has fully provided for the amount due to the uncertainties around collection.

Tax

Income Tax

$'000	Three Months ended December 31 2020	Three Months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Current tax	**816**	1,747	**7,384**	10,657
Deferred tax	**2,296**	1,223	**3,356**	2,326

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, 2020 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 $18.5 million (December 31, 2019: $15.2 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")

$'000	Three Months ended December 31 2020	Three Months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
APT	**589**	1,304	**4,054**	6,587

Under the terms of the PSA, APT is payable when the Company has recovered its costs plus a specified return out of Cost Gas revenues and Profit Gas revenues. As a result: (i) no APT is payable until the Company recovers its costs out of Additional Gas revenues plus an annual operating return under the PSA of 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"); and (ii) the maximum APT rate is 55% of the Company's Profit Gas when costs have been recovered with an annual return of 35% plus the percentage change in PPI.

The timing and the effective rate of APT depends on the realized value of Profit Gas 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 over the term of the PSA. The forecast takes into account the timing of future development capital spending. As at December 31, 2020 the current portion of APT payable was $11.5 million (December 31, 2019: $11.9 million) with a long-term APT payable of $24.8 million (December 31, 2019: $32.3 million).

The effective APT rate for the quarter of 17.1% (Q4 2019: 16.8%) has been applied to Company Profit Gas of $3.4 million (Q4 2019: $7.8 million), and an average effective APT rate of 16.8% (2019: 19.0%) has been applied to Company Profit Gas of $24.1 million (2019: $34.6 million) for the year ended December 31, 2020. Accordingly, $0.6 million (Q4 2019: $1.3 million) and $4.1 million (2019: $6.6 million) have been recorded for the quarter and for the year ended December 31, 2020, respectively.

Management's Discussion & Analysis continued

Working Capital

Working capital as at December 31, 2020 was $74.2 million (December 31, 2019: $107.0 million) and is detailed in the table below:

$'000	As at December 31	2020		2019
Cash and cash equivalents		**104,190**		93,899
Investment in short term bonds		**–**		44,756
Trade and other receivables				
Songas	**6,624**		8,763	
TPDC	**7,417**		7,284	
TRA	**5,337**		–	
Industrial customers and other receivables	**10,960**		10,287	
Loss allowance	**(8,458)**	**21,880**	(4,167)	22,167
Prepayments		**898**		6,752
		126,968		167,574
Trade and other payables				
TPDC share of Profit Gas revenue[1]	**25,570**		33,134	
Songas	**2,062**		2,354	
Other trade payables and accrued liabilities	**11,655**		12,673	
Current portion of Additional Profits Tax	**11,489**	**50,776**	11,940	60,101
Tax payable		**1,956**		501
		52,732		60,602
Working capital		**74,236**		106,972

[1] The balance of $25.6 million payable to TPDC represents TPDC's share of Profit Gas revenue, primarily related to unpaid gas deliveries to TANESCO, net of $4.8 million (2019: $4.9 million) of tax recoverable by the Company. 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 $14.9 million in 2020 and an additional $6.4 million in January 2021.

Financial Instruments

Current financial instruments of the Company include cash and cash equivalents, investment in short term bonds, trade and other receivables, trade and other payables 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 forecasted debt and interest payments ($7.7 million) and capital expenditure ($9.5 million) for 2021. The Company hasn't incurred any losses from debtors in 2020 and does not expect to incur any losses from debtors in 2021. 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.

TANESCO Receivable

As at December 31, 2020 the current receivable from TANESCO was $ nil (December 31, 2019: $ nil). During Q4 2020 and the year ended December 31, 2020 the amounts received from TANESCO were in excess of the revenue recognized for gas deliveries to TANESCO. The TANESCO long-term receivable as at December 31, 2020 was $27.6 million with a provision of $27.6 million compared to $47.5 million (with a provision of $47.5 million) as at December 31, 2019. In Q2 2020 the Company invoiced TANESCO $6.5 million (Q2 2019: $ nil) under the take or pay provision within the PGSA. The invoice has not been recognized in these financial statements as it does not meet revenue recognition criteria with respect to assurance of collectability. Subsequent to December 31, 2020 the Company invoiced TANESCO $6.5 million for 2021 gas deliveries and TANESCO has paid the Company $7.9 million.

Capital Expenditures

The capital expenditures in 2020 primarily related to the Compression Contract and the capital expenditures in 2019 primarily related to the refrigeration project for the Songas Infrastructure (does not include capitalized leases).

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Pipelines and infrastructure	**16,310**	1,007	**27,117**	4,153
Other capital expenditures	**5**	7	**24**	18
	16,315	1,014	**27,141**	4,171

Capital Requirements

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

In order to sustain current levels of production beyond 2021, it is necessary to install compression facilities to maintain throughput of the Songas Infrastructure over the remaining term of the PSA. Failure to do so will gradually lead to a significant reduction in production as field pressure declines below the level required to deliver gas to the Dar es Salaam power sector and industrial customers. As at the date of this report, the Company's only significant contractual commitment is in relation to the $38.0 million fixed price turn-key Compression Contract, $24.7 million of which has been paid to date. The remaining expenditures forecasted under this contract are $9.5 million in 2021 and $3.8 million in 2022. The compression facilities are expected to be operational by the end of Q2 2022.

During the year the Company implemented a flowline decoupling project to install dedicated flowlines to onshore wells SS-10 and SS-11 at a cost of $1.3 million. These two wells have hitherto been coupled to the 4" flowlines used by wells SS-3 and SS-4. The new decoupled flowlines have been constructed and were tied into the Songas Infrastructure plant during Q1 2021. The project is expected to increase production potential by approximately 10 MMcfd.

The Company intends to remediate the onshore SS-10 well by replacing the production tubing in the well during Q3 2021. The Company is also in discussions with Songas to remediate two additional onshore wells (SS-3 and SS-4) owned by Songas as part of the same program. A contiguous remediation program will reduce the capital expenditure required per well as a result of shared costs, particularly concerning rig mobilization and demobilization. All three wells will require replacement of their original carbon steel tubing completions with corrosion resistant tubing completions. Wells SS-3 and SS-4 are currently suspended and shut-in respectively. SS-10 well is still producing but, due to progressive corrosion of its production tubing identified by the Company's corrosion monitoring program, the work needs to be carried out this year. The Company is currently determining the costs of the workover program and expects the tender results from service providers including the workover rig before the end of Q2 2021.

Long-term Receivables

	As at December 31	
$'000	2020	2019
VAT – Songas workovers	**2,205**	2,205
Lease deposit	**9**	45
	2,214	2,250

In 2017, based on agreement with TPDC, $12.3 million relating to the Songas share of workover costs of the wells SS-5 and SS-9 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 action to collect the Songas share of workover costs from 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	2020	2019
Total amounts invoiced to TANESCO	**111,234**	118,861
Unrecognized amounts not meeting revenue recognition criteria[1]	**(83,685)**	(71,407)
Loss allowance	**(27,549)**	(47,454)
	–	–

[1] The amount includes invoices for interest on late payments and invoices relating to differences between gas contracted for delivery versus gas taken by TANESCO. In April 2021 TANESCO paid the take or pay invoice of $5.0 million for the 2015-2016 contract year for gas to be taken by June 30, 2021.

Management's Discussion & Analysis continued

Long-term Loan

In 2015 PAET obtained the Loan of $60 million from the IFC. The Loan was fully drawn down in 2016.

The Loan is to be repaid through six semi-annual payments of $5 million starting April 15, 2022 and one final payment of $25.2 million due on April 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 is guaranteed by the Company to a maximum of $30 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 fulfilment 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.

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.

There were 1,750,495 Class A Shares and 24,387,460 Class B Shares outstanding as at December 31, 2020. As at the date of this report there were a total of 1,750,495 Class A Shares and 18,233,614 Class B Shares outstanding following the completion of the 2021 SIB of CDN$40.0 million on January 22, 2021.

Cash Flow Summary

	Three Months ended December 31		Year ended December 31	
$'000	2020	2019	2020	2019
Operating activities				
Net income	**7,698**	12,886	**29,121**	26,346
Non-cash adjustments	**2,791**	8,139	**25,637**	27,911
Interest expense	**2,370**	1,621	**7,887**	8,279
Changes in non-cash working capital[1]	**6,510**	(17,595)	**(16,140)**	(27,663)
Net cash flows from operating activities	**19,369**	5,051	**46,505**	34,873
Net cash from investing activities	**28,633**	21,024	**17,720**	17,796
Net cash (used in)/from financing activities	**(42,386)**	1,616	**(54,408)**	(23,420)
Increase in cash	**5,616**	27,691	**9,817**	29,249

1 See Consolidated Statements of Cash Flows

The Company's net cash flows from operating activities increased by 283% for Q4 2020 and by 33% for the year over the comparable prior year periods. The increase for Q4 2020 was mainly a result of fluctuations in non-cash working capital and was respectively offset by changes in net income. Changes in non-cash working capital for the year were affected by the payment in March 2020 of the 2019 current APT of $11.9 million (2019: $ nil). Increases in net cash flows used in investing activities are mainly a result of the increased investment under the Compression Contract and the conversion of short-term bonds to cash in 2020. Changes in cash from and used in financing activities are primarily a result of the 2020 SIB and NCIB.

Related Party Transactions

The Chairman of the Company's Board of Directors is counsel to Burnett, Duckworth and Palmer LLP, a law firm that provides legal advice to the Company and its subsidiaries. Fees for services provided by this firm totaled $0.3 million during Q4 2020 (Q4 2019: $0.2 million) and $1.0 million for the year (2019: $0.4 million).

As at December 31, 2020 the Company had a total of $0.1 million (December 31, 2019: $0.2 million) recorded in trade and other payables in relation to the related party.

Substantial Issuer Bid, Normal Course Issuer Bid and Dividends

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

During Q2 2020 the Company completed the NCIB for its Class B Shares. Under the NCIB, the Company repurchased 477,500 Class B Shares at a weighted average price of CDN$5.32 per Class B Share for aggregate consideration of approximately CDN$2.5 million.

On November 18, 2020 the Company announced the approval of the new Dividend and Distribution Policy confirming the Company will be paying quarterly dividends to holders of Class A and Class B Shares.

On December 14, 2020 the Company announced the commencement of the 2021 SIB at a price of not less than CDN$6.50 and not more than CDN$7.50 per Class B Share. On January 22, 2021 the Company announced the final results of the 2021 SIB, whereby it repurchased and canceled a further 6,153,846 Class B Shares at a price of CDN$6.50 per share. This represented an aggregate purchase price of CDN$40.0 million, 25.2% of the total number of outstanding Class B Shares and 23.5% of the total number of the Company's issued and outstanding shares.

All issued capital stock is fully paid.

Dividend Summary

Declaration date	Record date	Payment date	Amount per share *(CDN$)*
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
November 28, 2019	December 31, 2019	January 31, 2020	0.06
September 17, 2019	September 30, 2019	October 31, 2019	0.06
May 29, 2019	June 30, 2019	July 31, 2019	0.06
January 22, 2019	March 31, 2019	April 30, 2019	0.05

Consolidation

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

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

[1] The companies were wound up during 2020.

Management's Discussion & Analysis continued

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, 2020 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. The aggregate value of these Class A common shares will equal the amount of any outstanding redemption.

There is no credit risk associated with the Preference Shares as a consequence of Swala having the obligation to redeem them by returning the equivalent value of Class A common shares for any overdue and outstanding amounts. A reconciliation of the non-controlling interest is detailed below:

	As at December 31	
$'000	2020	2019
Balance, beginning of year	**163**	(513)
Share of post-disposition income	**1,360**	1,628
Dividends paid	**–**	(952)
Balance, end of year	**1,523**	163

Contingencies

Taxation

					As at December 31	
Amounts in $'millions					2020	2019
Area	Period	Reason for dispute	Principal	Interest	Total	Total
Pay-As-You-Earn ("PAYE") tax	2008-16	PAYE tax on grossed-up amounts in staff salaries which are contractually stated as net.	**1.2**	**0.4**	**1.6**(1)	1.5
Withholding tax ("WHT")	2005-16	WHT on services performed outside of Tanzania by non-resident persons, on deemed dividends, loan interest and other services.	**5.7**	**3.0**	**8.7**(2)	8.3
Income tax	2008-16	Deductibility of capital expenditures and expenses (2009, 2012, 2015 and 2016), additional income tax (2008, 2010, 2011 and 2012), tax on repatriated income (2012), deemed branch dividends (2015 and 2016), foreign exchange rate application (2013 and 2015) and underestimation of tax due (2014).	**35.1**	**17.0**	**52.1**(3)	50.9
VAT	2008-18	Output VAT on imported services and SSI Operatorship services (2008-16); interest on VAT decreasing adjustments and input VAT on services (2017 and 2018).	**2.9**	**3.9**	**6.8**(4)	5.7
			44.9	**24.3**	**69.2**	66.4

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 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.

Contingencies continued

Taxation continued

During 2019 following the completion of audits for the years 2015 and 2016, the TRA issued assessments for $15.1 million relating to corporation tax, withholding tax, VAT, excise duty and payroll tax. With the exception of $0.1 million of VAT and WHT on rent which the Company has conceded, the Company has objected to the other components of the assessment and requested a waiver of the deposit required to allow a dispute of the assessment and is awaiting a TRA response. The Company has also objected to several other assessments from the TRA demanding deposits to allow the dispute to be made and is awaiting Tax Revenue Appeal Board ("TRAB") hearing dates. Management, with advice from its legal counsels, has reviewed the Company's position on the objections and appeals related to the disputed amounts and has concluded that no provision is required with regard to these matters and that the maximum potential exposure is $63.6 million (December 31, 2019: $66.4 million).

During 2020, acting under instructions from the TRA, the PAET's commercial bank in Tanzania transferred to the TRA the full principal tax amount of $2.6 million together with interest of $2.7 million relating to the disputed 2008-10 output VAT. Subsequently, the Company filed an appeal for review with the Tanzanian Court of Appeal ("CAT"). These amounts have been recorded in trade and other receivables and are fully provided for pending the resolution of the dispute.

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.

The process of appealing assessments issued by TRA start 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 and filed an application for judicial review at CAT. TRA instructed PAET's commercial bank to transfer the full principal amount in dispute to TRA;

(b) 2015-16 ($1.3 million): The Company has objected to an assessment and is awaiting a TRA response;

(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. Waiting to see whether TRA will file an application to object to the CAT ruling;

(b) 2010 ($0.1 million): TRAT ruled in favor of TRA. The Company has filed a notice of intention to appeal with CAT and is awaiting a TRAT written judgment to finalize the appeal;

(c) 2015-16 ($7.0 million): The Company objected to several assessments in 2019 issued by TRA with regards to withholding tax and is awaiting a TRA response. The Company appealed to TRAB against the one-third deposit required to admit the objection and is awaiting a TRAB judgment;

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

(b) 2009 ($2.8 million): The Company has filed an application for review of a CAT judgment and is awaiting a hearing date ($2.0 million). The Company objected to an amended assessment from TRA ($0.8 million) for being time-barred and arbitrary and is awaiting a TRA response;

(c) 2010 ($2.4 million): The Company is awaiting a judgment from a TRAB hearing held in 2019;

(d) 2011 ($1.9 million): The Company is awaiting a judgment from TRAB ($1.7 million). The Company is also awaiting a TRA response on an objection of an assessment ($0.2 million);

(e) 2012 ($15.4 million): The Company has objected to TRA assessments with respect to understated revenue, timing of deductibility of capital expenditures, expenses and tax on repatriated income. The Company is awaiting a CAT hearing date for waiver of a deposit payment required to file its objection;

(f) 2013 ($9.1 million): The Company filed an objection to TRA assessment ($0.1 million) and is awaiting a response. The Company has objected to two assessments as being time-barred without merit and tax on repatriated income ($9.0 million) and is in the process of appealing to CAT that a deposit is required to file the objection;

(g) 2014 ($11.6 million): The Company filed an objection to a TRA assessment ($3.3 million) and is in the process of appealing to CAT that a deposit is required to file the objection. TRA issued two additional assessments for the year for corporation tax of $5.3 million and tax on repatriated income of $3.1 million. The Company has objected to the assessments and is awaiting a TRA response;

(h) 2015-16 ($8.3 million): The Company filed objections to TRA assessments and is awaiting a response;

(4) (a) 2008-2010 ($5.3 million): Acting under instructions from TRA, PAET's commercial bank in Tanzania transferred the full disputed amount of $5.3 million to TRA. The Company has filed an appeal at CAT and is awaiting a decision;

(b) 2015-16 ($0.3 million): The Company has filed an objection to a TRA assessment and is awaiting a response;

(c) 2017-18 ($1.2 million) The Company has filed an objection to a TRA assessment and is awaiting a response. The Company has objected 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 is 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. 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 entitlement under the terms of the PSA.

Management's Discussion & Analysis continued

Recent Accounting Changes

The following recent accounting changes that became effective on January 1, 2020 have been adopted by the Company and have had no material effect on the Company:

- On October 22, 2018, the International Accounting Standards Board (the "IASB") issued "Definition of a Business (Amendments to IFRS 3)" aimed at resolving the difficulties that arise when an entity determines whether it has acquired a business or a group of assets. The amendments are effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2020.
- On October 31, 2018, the IASB issued "Definition of Material (Amendments to IAS 1 and IAS 8)" to clarify the definition of 'material' and to align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Interim 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, 2020.

Quarterly Results Summary

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

Figures in $'000	2020				2019			
except where otherwise stated	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	**21,980**	20,859	17,320	17,715	23,212	21,453	20,994	19,936
Net income attributable to shareholders	**7,375**	1,487	6,254	12,645	12,642	2,583	6,718	2,775
Earnings per share								
– basic and diluted ($)	**0.28**	0.06	0.27	0.39	0.36	0.07	0.20	0.08
Net cash flows from operating activities	**19,369**	12,793	13,516	827	5,051	7,603	8,978	13,241
Adjusted funds flow from operations[1]	**12,348**	11,847	7,380	7,569	13,479	10,180	10,490	9,064
Capital expenditures	**16,315**	9,412	1,005	489	1,014	652	1,413	1,092

1 See non-GAAP measures.

Revenue increased steadily throughout 2019, as a result of increased deliveries to TANESCO and TPDC. The decrease in the first half of 2020 was mainly due to increased use of hydropower during an extended rainy season which led to a fall in sales to the Power sector. Revenue rose during Q3 2020 and Q4 2020 as the Power sector demand for gas increased to compensate for a reduction in the available hydropower.

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

- The collection of long-term TANESCO arrears, and the corresponding release of bad debt provisions, led to an increase in the reversal to loss allowances in Q2 2019, Q4 2019, Q1 2020, and Q4 2020. The Company collected $3.5 million, $7.5 million, $10.1 million, and $3.5 million of TANESCO long-term arrears, respectively. The decrease in Q3 2019, notwithstanding the increase in revenue, was a result of lower collections of TANESCO long-term arrears compared to other periods;
- Decrease in Q2 2020 was a result of lower revenue and a lower collection of TANESCO arrears as compared to Q1 2020;
- 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.

Quarterly Results Summary continued

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. This is the primary reason for the large cash flows in Q1 2019. The fluctuations throughout 2019 were primarily a result of the increase in revenue from quarter to quarter, payments to TPDC for profit share and changes in non-cash working capital. The decrease in Q1 2020 and the consequent increase in Q2 2020 is primarily a result of the annual payment of the 2019 current liability associated with APT in Q1 2020. The decrease in Q3 2020 is mainly a result of decreased collections from TANESCO compared to prior periods; correspondingly, the increase in Q4 2020 is mainly a result of the TRA provision of $5.3 million and increased collections from TANESCO compared to the previous quarter.

Adjusted funds flow from operations from Q1 2019 to Q4 2019 showed consistent growth coinciding primarily with the increase in revenue. The increase in Q4 2019 was primarily related to the increased deliveries through the NNGI following the signing of the new LTGSA which resulted in TPDC taking gas deliveries as high as 40 MMcfd during the quarter. The decline from Q4 2019 to Q2 2020 is reflective of the decrease in revenue due to the availability of hydropower with revenue again increasing in Q3 2020 and Q4 2020.

Capital expenditures in 2019 and Q1 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 Compression Contract.

Selected Annual Financial Information

Selected annual financial information derived from the audited consolidated financial statements for the years ended December 31, 2020, 2019 and 2018 is set out below:

Figures in $'000 except per share amount	2020	2019	2018
Revenue	**77,874**	85,595	57,766
Net income attributable to shareholders	**27,761**	24,718	13,270
Earnings – basic and diluted ($ per share)	**1.00**	0.71	0.38
Cash dividends declared (CDN$ per Class A and B Shares)	**0.28**	0.23	0.60
Net cash flows from operating activities	**46,505**	34,873	28,752
Adjusted funds flow from operations[1]	**39,144**	43,213	19,255
Total non-current liabilities	**98,008**	102,603	104,345
Total assets	**242,612**	271,772	262,441

[1] See Non-GAAP measures.

Revenue increased by 48% in 2019 compared to 2018. This was a result of increased sales to TANESCO and TPDC through NNGI as well as a higher current income tax adjustment. The 9% decrease of revenue in 2020 compared to 2019 was primarily due to lower power sales volumes and a lower current income tax adjustment.

The increases in net income attributable to shareholders in 2019 and in 2020 were primarily due to the changes in revenue and increased reversal of loss allowances related to the collection of TANESCO arrears.

The dividend in 2018 of CDN$0.60 per share was approved following the sale of a 7.9% interest in PAEM. In 2019 the Company approved quarterly dividends, CDN$0.05 per share for Q1 2019 and CDN$0.06 per share for Q2, Q3 and Q4 2019. In 2020 the Company approved quarterly dividends, CDN$0.06 per share for Q1 and Q2 2020 and CDN$0.08 per share for Q3 and Q4 2020. Please refer to the table in the Substantial Issuer Bid, Normal Course Issuer Bid and Dividends section of this MD&A.

The increases in net cash flows from operating activities compared to net income are primarily related to the changes in non-cash working capital associated with decreases in prepayments and in trade and other receivables.

The changes in adjusted funds flow from operations primarily relate to increases and decreases in deliveries and revenue between periods.

Total non-current liabilities did not change significantly between the years. The decrease of $1.7 million in 2019 compared to 2018 was primarily due to the repayment of a portion of the Loan. The $4.6 million decrease in 2020 compared to 2019 was a result of the repayment of a portion of the APT.

Total assets increased in 2019 compared to 2018, primarily because of increased collections from TANESCO increasing cash and investment balances. The 11% decrease in 2020 compared to 2019 is mainly a result of the 2020 SIB. Please refer to the Substantial Issuer Bid, Normal Course Issuer Bid and Dividends section of this MD&A.

Non-GAAP Measures

The Company evaluates its performance using a number of non-GAAP (generally accepted accounting principles) measures. These non-GAAP measures are not standardized and therefore may not be comparable to similar measurements of other entities.

- Adjusted funds flow from operations represents net cash flows from operating activities less interest expense and reversal of loss allowances related to the collection of the TANESCO arrears and a previously disputed Songas operatorship receivable before changes in non-cash working capital. This is a performance measure that management believes represents the Company's ability to generate sufficient cash flow to fund capital expenditures and/or service debt.

Management's Discussion & Analysis continued

Non-GAAP Measures continued

$'000	Three Months ended December 31 2020	Three Months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Net cash flows from operating activities	**19,369**	5,051	**46,505**	34,873
Interest expense	**(2,370)**	(1,621)	**(7,887)**	(8,279)
Reversal of loss allowance – TANESCO arrears	**(3,478)**	(7,546)	**(19,905)**	(11,044)
Reversal of loss allowance – collection of disputed Songas receivables	**–**	–	**(1,046)**	–
Loss allowance – TRA	**5,337**	–	**5,337**	–
Changes in non-cash working capital	**(6,510)**	17,595	**16,140**	27,663
Adjusted funds flow from operations	**12,348**	13,479	**39,144**	43,213

- Operating netbacks represent the profit margin associated with the production and sale of Additional Gas and is calculated as revenues less processing and transportation tariffs, TPDC's revenue share, operating and distribution costs per one thousand standard cubic feet of Additional Gas. This is a key measure as it demonstrates the profit generated from each unit of production.
- Adjusted funds flow from operations per share is calculated on the basis of the adjusted funds flow from operations divided by the weighted average number of shares, similar to the calculation of earnings 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.

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, 2020 audited consolidated financial statements for a description of estimates and judgments.

Business Risks

Industry and Business Conditions

Competition and operational risk

The oil and gas industry is intensely competitive and the Company competes with other companies which possess greater technical and financial resources. Oil and 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, 25 km 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 oil and natural gas markets or delay our oil and 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.

Business Risks continued

Industry and Business Conditions continued

COVID-19

The emergence of COVID-19 has resulted in travel bans, mandatory and self-imposed quarantines and isolations, social distancing and the closing of non-essential business which has had a negative impact on economies world-wide. The Company has taken appropriate action to protect employees such as social distancing, working from home where possible and ensuring staff who work on rotation at the Songas Infrastructure are placed into quarantine prior to assuming regular duties. 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 and closures and expansion delays. Although the Company has lived with the impact of COVID-19 for over a year, 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 counter-parties 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 gas, a prolonged decline in world oil prices could impact the competitiveness and demand for 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. The Company does not maintain any key life insurance on any of its employees or officers.

Environmental regulation

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

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 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.

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

Cyber attack

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

Management's Discussion & Analysis continued

Business Risks continued

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.

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 partially or wholly with debt, which may temporarily increase the Company's debt levels above industry standards. The Company 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 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 deliverability. In addition, any difficulties relating to the operation or performance of the 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 Government 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 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 our sole source of our 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 us. 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.

Financial continued

Foreign operations and concentration risk continued

Country risk

The geographic location of the license 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 oil and gas, develop or produce our license areas by limiting access to qualified personnel, increasing costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and oil and 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.

The recent disputed actions taken by the TRA to seize funds from PAET's bank account using Agency Notices further highlight the country risks of operating in Tanzania. There is no assurance that such disputes will be resolved in favor of the Company and that further such actions may have a material adverse effect on our activities and ability to operate and monetize our interests in Tanzania.

Corruption

Tanzania ranks 94 out of 180 on the 2020 Transparency International Corruption Index (2019: 96 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. 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 operations or future cash flows of the Company.

PSA operations are regulated by national and parastatal organizations including the energy regulators (PURA and EWURA), and TPDC. Under our Gas Agreement ("GA") with the GoT, TPDC and Songas, the Company has the right to market and sell Additional Gas. The Amended and Restated Gas Agreement ("ARGA") 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 Additional Gas Plan 2 ("AGP2") 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.

We have had, and continue to have, disagreements with TPDC 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 Petroleum Act 2015, insist on the right to approve the budget. We have previously had, and continue to have, disagreements with TPDC and the GoT regarding certain of our rights and responsibilities under the PSA. TPDC has 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, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

Management's Discussion & Analysis continued

Financial continued

Contractual, regulatory and legislation risk continued

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 a new regulator to oversee the upstream sectors, PURA and conferred upon TPDC the status of National Oil Company as the sole aggregator of natural gas in the country. Under the Petroleum Act Article 260 (3) preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party natural gas customers. 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(l) of the Petroleum Act which may give rise to additional uncertainty. These changes could impact our 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. 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 third of these Acts 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 Income Tax Act 2004 ("ITA, 2004") for mining and for petroleum to be effective commencing in 2018. Subsequent to this, further changes were made by the Written Laws (Miscellaneous Amendments) Act, 2017 ("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 our contracts with the GoT permit this.

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 (see (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 Protected Gas price 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, subject to TPDC being able to elect to participate in a development program only once and TPDC having to pay a proportion of the costs of such development program by committing to pay between 5% and 20% of the total costs ("Specified Proportion"). If TPDC does not notify the Company within 90 days of notice from the Company that the 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, 2020, there are no planned drilling activities to the end of the license.

Management's Discussion & Analysis continued

Principal Terms of the PSA and Related Agreements continued

Revenue Sharing Terms and Taxation continued

(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 2011 the Company signed a re-rating agreement with TANESCO, TPDC and Songas (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 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, Energy and Water Regulatory Authority ("EWURA"). Songas terminated the Re-Rating Agreement in 2014 although there remains a disagreement as to its current status.

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 processing capacity at the Songas Infrastructure remains unaltered and is fully available for the Company's utilization along with the additional capacity within the NNGI which includes two gas processing facilities and pipelines supplying gas from the Mtwara Region of Tanzania and Songo Songo Island to Dar es Salaam. The PGSA provides for passing on to TANESCO any tariff to be charged to the Company in the event that a new tariff is approved.

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 wells SS-10, SS-11 and SS-12 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 endeavours basis. 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.

(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 in the knowledge that the Profit Gas share can increase with larger daily gas sales and that the costs will be recovered with a 25% plus PPI annual return before APT becomes payable. APT can have a significant negative impact on project economics if only limited capital expenditure is incurred.

Principal Terms of the PSA and Related Agreements continued

Revenue Sharing Terms and Taxation continued

(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 (235 Bcf as at December 31, 2020). 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.

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 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 and $3.14/mcf on July 1, 2020.

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 endeavours 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 not contributed any costs nor provided any formal notice of intent to do so.

Management's Discussion & Analysis continued

Forward-Looking Statements

This MD&A contains forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. All statements, other than statements of historical fact included in this MD&A, which address activities, events or developments that Orca expects or anticipates to occur in the future, are forward-looking statements. Forward-looking statements often contain terms such as may, will, should, anticipate, expect, continue, estimate, believe, project, forecast, plan, intend, target, outlook, focus, could and similar words suggesting future outcomes or statements regarding an outlook. More particularly, this MD&A contains, without limitation, forward-looking statements pertaining to the following: the Company's expectations regarding supply and demand of natural gas; the Company's expectations regarding timing for the completion of installation of compression on the Songas Infrastructure; the expected expenditures required to complete the installation of the compression on the Songas Infrastructure; the growth of the Tanzanian domestic gas markets; anticipated production volumes and increased well deliverability as a result of the installation of compression on the Songas Infrastructure; current and potential production capacity of the Songo Songo gas field; the anticipated increase in production capabilities following the implementation of the flowline decoupling project; expected timing, cost and ability to remediate three onshore wells, SS-3, SS-4 and SS-10; timing for receiving tender results in respect of the workover proram; 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 Company's expectations in respect of the resolution of the dispute with the TRA relating to the loss allowance; the timing and effective rate of the APT payable by the Company; the Company's expectations in respect of its appeals on the decisions of the TRAB and TRAT and other statements under "Contingencies – Taxation"; the Company's expectation that the Songas Infrastructure production volumes will not be restricted; the Company's ability to produce additional volumes; the availability of debt financing; the Company's expectation that it can expand and maintain the deliverability of gas volumes in excess of the existing Songas Infrastructure; and the expectation that the IASB pronouncements will not have any impact on the Company's consolidated financial statements. 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; risk that the potential financing solutions to resolve the TANESCO arrears are not implemented by the Tanzanian government; potential negative effect of the Company's decision to suspend efforts to acquire and develop an integrated gas business in other African countries; 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 licence; 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 new 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 the 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 on the timeline anticipated; failure to obtain tender results from service providers in respect of the workover program on the timeline anticipated; risks associated with negotiating with foreign governments; inability to satisfy debt conditions of financing; failure to successfully negotiate agreements; risk that the Company will not be able to fulfil its contractual obligations; reduced global economic activity as a result of the COVID-19 pandemic, including lower demand for natural gas and a reduction in the price of natural gas; the potential impact of the COVID-19 pandemic 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. 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.

Forward-Looking Statements continued

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, that the Company will be able 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 development program are in line with estimates; that there will continue to be no restrictions on the movement of cash from Mauritius or Tanzania; the impact of the COVID-19 pandemic 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 further 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 labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; the impact of increasing competition; conditions in general economic and financial markets; effects of regulation by governmental agencies; that the Company's appeal of various tax assessments will be successful; that the enactment of the Petroleum Act, 2015 and new legislation in Tanzania will not impair the Company's rights under the PSA to develop and market natural gas in Tanzania; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and other matters.

The forward-looking statements contained in this MD&A are made as of the date hereof and 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	**1P**	Proven reserves
MMcf	Million standard cubic feet	**2P**	Proven and probable reserves
Bcf	Billion standard cubic feet	**kWh**	Kilowatt hour
Tcf	Trillion standard cubic feet	**MW**	Megawatt
MMcfd	Million standard cubic feet per day	**$**	US dollars
MMbtu	Million British thermal units	**CDN$**	Canadian dollars