BYRONENERGY LIMITED

Quarterly Report for the Period Ended 31 December 2022

Summary

- Byron generated quarterly net sales revenue for the December 2022 quarter of approximately US$ 14.2 million, down approximately 26% on the September 2022 quarter with the reduction due to a combination of lower realised prices and lower production volumes; net sales revenue for the December 2022 half year of US$ 33.4 million was approximately 51% higher than in the December 2021 half year;

- Byron's share of oil and gas production (net sales volume) for the December 2022 quarter was 153,716 barrels of oil and 440,930 mmbtu of gas compared to the previous quarter of 176,160 barrels of oil and 512,350 mmbtu of gas, with the reduction due to a combination of natural decline in production and compressor downtime mainly caused by freezing temperatures and high winds brought by Winter Storm Elliott;

- Realised net prices of US$ 76.23 per barrel of oil and US$ 5.25 per mmbtu of natural gas net to Byron after quality adjustments, oil and gas transportation charges and royalties were achieved during the December quarter (September 2022 quarter: net realised net prices of US$ 84.70 per barrel of oil and US$ 8.03 per mmbtu of natural gas); and

- Outstanding Crescent Midstream promissory notes of US$2.0 million at the end of September 2022 quarter was fully repaid on schedule in October and November 2022. Byron's total borrowings were reduced by 37% from US$5.4 million in the September quarter to US $3.4 million.

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 31 Dec 2022:	**1,081.4 million**
Quoted shares:	**1,081.4 million**
Options on issue (unquoted):	**2.0 million**
Cash at Bank 31 Dec 2022:	**US$2.71 million**
Borrowings 31 Dec 2022:	**US$3.42 million** (excluding oil revenue prepayment)
Market Capitalisation at 31 Dec 2022:	**A$124 million (@A$0.115 / share)**

Directors

Doug Battersby (Non-Executive Chairman)
Maynard Smith (Chief Executive Officer)
Prent Kallenberger (Chief Operating Officer)
Charles Sands (Non-Executive Director)
Paul Young (Non-Executive Director)
William Sack (Executive Director)

Company Secretary and Chief Financial Officer

Nick Filipovic

Corporate

Issued Capital

As at 31 December 2022, Byron's issued capital comprised:-

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	1,081,395,102*	1,081,395,102*	Nil
Options (Expiring on 31 December 2024 with an exercise price of A$0.16)	2,000,000	Nil	2,000,000

*Includes 41,100,000 shares subject to voluntary escrow. These shares are already quoted on the ASX and have the same rights as all other ordinary shares issued by Byron, except they are placed in trading lock. The shares in voluntary escrow are held by executive directors, staff and contractors of the Company

Corporate (cont.)

Borrowings and oil revenue prepayment

As at 31 December 2022, Byron's outstanding loans comprised:-

Lender	US$ M	A$ M	31 Dec 2022 US$ equivalent (@A$1=US$0.6775)	30 Sep 2022 US$ equivalent (@A$1=US$0.6502)
Directors	2.00	1.75	3.18	3.14
Shareholder	-	0.35	0.24	0.23
Crescent Midstream	-	-	-	2.00
Total	**2.00**	**2.10**	**3.42***	**5.37**

*as at 31 December 2022, Byron also had US$ 0.6 million in insurance premium financing outstanding

Crescent Midstream Promissory Note

The outstanding principal balance of the Crescent Promissory Note of US$ 2.00 million as at 30 September 2022 was fully repaid during the December 2022 quarter.

Directors' and Shareholder Loans

Byron's outstanding loans of approximately US$ 3.42 million as of 31 December 2022, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder were due to be repaid on 31 March 2023. Subsequent to 31 December 2022, all lenders agreed to extend the repayment date of the loans by 12 months, from 31 March 2023 to 31 March 2024.

Oil revenue prepayment

In May 2022, the Company's oil purchaser provided access to further funding of US$ 11.0 million through the prepayment of future oil revenue. The prepayment will be repaid over eight monthly instalments with the first instalment paid in September 2022. The fee for this prepayment is approximately US$ 1 per produced barrel of oil until such time as the prepayment is repaid. During the December quarter 2022 Byron reduced the amount owing under the prepayment arrangement by US$3.0 million to a balance of US$6.625 million at 31 December 2022.

Cashflow

Byron generated receipts from customers of approximately US$ 16.3 million during the December 2022 quarter, compared to US$ 18.8 million for the September 2022 quarter. After deducting payments for production, development and other operating activities and deducting repayment of oil revenue prepayments, the net cash outflow from operating activities was US$ 0.7 million during the quarter. Byron ended the December quarter with a cash balance of US$ 2.7 million. All creditors in respect to drilling and completion of SM58 G3 and G5 wells were paid during the December quarter.

Consolidated statement of cash flows (US$ million)	Dec 22 quarter	Sep 22 quarter
Cashflow from operating activities		
Receipts from customers	16.3	18.8
Payments for production	-2.0	-1.3
Net receipts from production	**14.3**	**17.5**

Corporate (cont.)

Consolidated statement of cash flows (US$ million) (cont)	Dec 22 quarter	Sep 22 quarter
Cashflow from operating activities (cont)		
Payment for development (G3 & G5 wells)	-10.8	-19.5
Payments for other operating activities (net)	-1.2	-1.1
Receipts/(Repayments) of oil revenue pre-payment (net)	-3.0	-1.4
Net cash from / (used in) operating activities	**-0.7**	**-4.5**
Cash flows from investing activities		
Exploration and evaluation	-0.4	-0.9
Net cash from / (used in) investing activities	**-0.4**	**-0.9**
Cash flows from financing activities		
Net cash from / (used in) financing activities	**-2.0**	**-2.9**
Net increase / (decrease) in cash and cash equivalents for the period	**-3.1**	**-8.3**
Cash and cash equivalents at end of quarter	**2.7**	**5.8**

For further details on the December 2022 quarter cashflows refer to Appendix 5B.

Oil price hedging

Byron's realised prices for oil are a combination of hedged and unhedged volumes. As at 31 December 2022, the Company's oil hedging position is governed by a forward physical sale agreements (Forward Sale Agreement), which specifies a price per barrel in advance for each delivery period during the term of the contract.

The hedging counterparty for the Forward Sale Agreement is one of the global oil industry's "supermajors" and is also the purchaser of Byron's oil production under a mutually agreed long term purchase arrangement, which provides Byron with a stable, aligned counterparty.

Byron's hedged oil production as at 31 December 2022 is as follows:-

Period *Forward Sale Agreements*	Daily Hedged Volume (bopd)	Period Hedged Volume (bbl)	NYMEX WTI Fixed Base Price Crude Oil*	NYMEX Roll Adjust	LLS/WTI Price Differential	Realised Price on Hedged Production *prior to Transportation Charges*
Jan-Mar 2023	200	18,000	US$80.95	unhedged	unhedged	To be determined

*WTI CMA base price is adjusted for NYMEX Roll, LLS/WTI price differentials and Transportation (estimated at -US$4.99) to arrive at a realised price.

Byron's total hedge position is less than 12% of the current net daily oil production with all existing hedges due to expire 31 March 2023.

Oil and Gas Production/Sales

Byron's share of oil and gas production and sales for the December 2022 quarter is summarised in the table below.

Production (sales)	Dec 2022 quarter	Sep 2022 quarter	Year to date 31 Dec 2022	Year to date 31 Dec 2021
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	63,451	75,572	139,023	162,017
Gas (mmbtu)	62,172	59,499	121,671	147,682
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	85,095	95,938	181,033	61,643
Gas (mmbtu)	377,780	452,265	830,045	1,251,475
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	5,170	4,650	9,820	10,717
Gas (mmbtu)	978	586	1,564	2,610
Total Net production (NRI basis)				
Oil (bbls)	**153,716**	**176,160**	**329,876**	**234,377**
Gas (mmbtu)	**440,930**	**512,350**	**953,280**	**1,401,767**

Aggregate oil and gas production and sales, net to Byron, were 153,716 bbls of oil and 440,930 mmbtu of gas for the December 2022 quarter compared to 176,160 bbls of oil and 512,350 mmbtu of gas for the September 2022 quarter. Lower oil and gas production was due to a combination of compressor downtime, resulting mainly from Winter Storm Elliot at the SM58 G Platform and the SM71F Platform during the latter part of December, and natural production decline.

The quarterly and financial year to date net sales revenue is summarised below.

Sale revenue (accrual basis) US$ million	Dec 2022 quarter	Sep 2022 quarter	Year to date 31 Dec 2022	Year to date 31 Dec 2021
Net sales revenue (Byron share on NRI basis)	14.2	19.2	33.4	22.1

Net sales revenue for the December 2022 quarter of approximately US$ 14.2 million, after quality adjustments, oil transportation charges and royalties, and down 26% compared to US$ 19.2 million for the prior quarter. Net sales revenue was lower for the December 2022 quarter, compared to the September 2022 quarter, mainly due to lower oil and gas production and lower realised oil and gas prices. Net sales revenue was up approximately 51% for the December 2022 half year compared to the corresponding six months in 2021, due to higher realised oil and gas prices and higher oil production partly offset by lower gas sales volumes.

For the December 2022 quarter, Byron realised an average oil price after adjustment for LLS price differentials and deductions for transportation, oil shrinkage and other applicable adjustments of US$ 76.23 per bbl (US$ 81.22 excluding transportation) compared to US$ 84.70 per bbl and US$ 89.69 per bbl respectively for the September 2022 quarter.

Byron realised an average gas price after transportation deductions of approximately US$ 5.25 per mmbtu for the December 2022 quarter (US$ 5.61 excluding transportation) compared to US$ 8.03 per mmbtu and US$ 8.39 per mmbtu respectively for the September 2022 quarter.

Project Updates

Salt Dome Projects

South Marsh Island 73 Salt Dome

The SM73 field encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 feet to 8,800 feet Total Vertical Depth. The majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

(a) South Marsh Island 71

Byron owns the South Marsh Island block 71 (SM71) a lease in the South Marsh Island Block 73 (SM73) field. Byron is the designated operator of SM71 and owns a 50% Working Interest (WI) and a 40.625% Net Revenue Interest (NRI) in the block, with Otto Energy Limited (Otto) group holding an equivalent WI and NRI in the block. As Otto did not participate in the drilling of the SM71 F4 well Byron is entitled to 100% WI/81.25% NRI in SM 71 F4 well, until payout.

Water depth in the area is approximately 137 feet.

Oil and gas production from the Byron operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well, commenced in mid-March 2020 until it was shut in September 2020. F4 resumed production in November 2021.

As of 31 December 2022, the SM71 F facility has produced approximately 4.4 million barrels of oil (Mmbo) (gross) since initial production began. The facility has also produced approximately 5.3 billion cubic feet of gas (Bcfg) (gross).

Total December 2022 quarter gross sales volumes for all wells on the SM71 F Platform totalled approximately 152,500 barrels of oil and 150,127 mmbtu of gas (September 2022 quarter, 185,087 barrels and 145,391 mmbtu). Lower oil production from SM71 F Platform for the December quarter was mainly due to lower oil production (higher water cut) from the F3 well, which averaged approximately 28% water cut for the December 2022 quarter compared to approximately 5% for the September 2022 quarter, and compressor downtime. Gas production for the December quarter was higher than for the September quarter due to the F3 well being placed on gas lift during the quarter. The F compressor went down on 18 December 2022, caused by freezing temperatures and high winds brought by Winter Storm Elliott, and was brought fully back on stream on 4 January 2023. Compressor repairs took longer than expected due to inclement weather. The increased water production from the F3 well is in line with Byron's production to models and Collarini reserve assessments. The F3 well was placed on gas lift during the December quarter and the D5 reservoir is being produced at a total fluid rate of approximately 2,400 bbls per day between the SM71 F1 and F3 wells. The updip SM71 F1 well continues to produce water free and the rate will be managed to optimize the D5 Sand reservoir's oil production.

The F2 and F4 wells are producing from the J1 Sand.

(b) South Marsh Island 58

Byron holds all the operator's rights, title, and interest in and to the South Marsh Island block 58 (SM58) lease to a depth of 13,639 feet subsea with 100% WI and 83.33% NRI. Below 13,639 feet subsea, Byron has a 50% WI (41.67% NRI) under a pre-existing exploration agreement. To date, all identified drilling opportunities on the SM58 lease

Oil and Gas Production/Sales (cont)

are above 13,639 feet subsea.

Byron has also earned a 100% WI in the SM69 E2 well (E2) under the Joint Exploration Agreement (JEA) with ANKOR group (ANKOR), acquired by W&T Offshore, Inc. (W&T Offshore) during the March 2022 quarter) which provided for the drilling of the E2 exploration well operated by Byron. By funding 100% of the E2 well Byron earned 100% WI and 80.33% NRI until E2 Project Payout, at which time and at the leaseholder's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI.

Water depth in the area is approximately 132 feet.

As of 31 December 2022, the SM58 G facility has produced approximately 7.7 Bcfg and 0.5 million barrels of oil and condensate (gross) on a cumulative basis from five wells (G1, G2, E2, G3 and G5).

The SM58 G1 well produces from the Upper O Sand and after producing 56.5-degree gravity condensate since inception of production, the G1 is now producing 36-degree dark oil at rates of around 80 bopd and no formation water. Gas and oil production from the G1 well has continued to follow a natural and predictable pressure decline.

The SM58 G2ST produces from the O Sand producing oil, gas and with associated formation water.

The SM58 G3 and G5 currently produce from the J Sand and L2 Sand respectively.

The SM69 E2 well produces from the K4/B65 Sand.

Production of oil, gas and any other liquids from the E2, located on SM69 E platform, flows to the Byron operated SM58 G platform where separation occurs before oil and gas are sent to sales pipelines. Unlike the E1 well production, E2 production is not subject to any third-party processing fees.

Total quarterly gross sales volumes for all wells on the SM58 G Platform, totalled 455,323 mmbtu of gas and 104,316 barrels of oil for the December 2022 quarter (September 2022 quarter 544,569 mmbtu of gas and 117,574 barrels of oil). Lower production from SM58 for the December quarter was mainly due to natural decline and compressor downtime. As previously reported, the G3 and G5 wells continue to decline with minimal aquifer support to date. The compressor went down on 22 December 2022 caused by freezing temperatures and high winds brought by Winter Storm Elliott, and was brought back on stream on 25 December 2022 but went down again on 1 January 2023 until 8 January 2023. Compressor repairs took longer than expected due to inclement weather. The SM69 E2 well is produced through the SM58 G platform and production has remained relatively steady with no water production. The compressor downtime did not affect production from the E2 well, located on the W&T Offshore operated SM69 E platform and piped back through a flowline to the SM58 G platform for processing and sale.

(c) South Marsh Island SM58 E1 well, SM 69 E Platform

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with one active producing well, the SM58 E1 well. The SM58 E1 was drilled from a surface location in SM69 to a bottom hole location in SM58 in 2011 and was initially completed in the K4 Sand (B65 Sand) which produced a total of 632,000 barrels of oil, 0.19 Bcfg of gas and 836,000 barrels of formation water before the well was recompleted in the K Sand in the March 2021 quarter.

Total December 2022 quarterly net sales volumes for the SM58 E1 well totalled 5,170 barrels of oil and 978 mmbtu (September 2022 quarter 4,650 barrels of oil and 587 mmbtu).

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

W&T Offshore, Inc is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM58 E1 well which surfaces from the SM69 E platform which is located in the NE corner of the SM69 block.

Main Pass 306

Byron currently holds 100% Working Interest and an 87.50% Net Revenue Interest leases on Main Pass blocks 293, 305 and 306 comprising the Main Pass 306 Field (MP306) which has produced approximately 96 MMBO and 108 Bcf of gas. MP306 is a structurally and stratigraphically complex salt dome which should lend itself to advance RTM interpretation techniques as employed at our SM58 salt dome project. These leases were acquired at the Gulf of Mexico, OCS Lease Sale 251 held in New Orleans, Louisiana on 15 August 2018.

As previously reported, Byron licensed 3D RTM seismic data that was reprocessed by the contractor (TGS) in 2022 and began interpretation. MP306 was discovered in 1969 and lies in approximately 200 feet of water. Byron's licensed data area allows the integration of all producing wells on the MP 306 salt dome and also ties recent discoveries in the area which may serve as analogues for any generated prospects. Byron's technical team completed the interpretation project during the December 2022 quarter. After a full evaluation it was determined that several previously identified potential drilling opportunities did not meet the Company's technical and economic risk criteria. Based on technical and economic basis, Byron will let the three leases expire at end of the lease term in October 2023. As a result, Byron expects to write-off the carrying value of the MP 306 leases, approximately US$1.6 million, in the financial report for the half year ended 31 December 2022.

Drilling Schedule

The expected start date for Byron's next round of drilling has been changed due to rig scheduling. The Enterprise Offshore Drilling 264 jack-up drilling rig is now expected to be available to Byron in mid-April 2023.

The Company is currently permitting several additional wells to allow for flexibility based on continuing geophysical and geological reviews and commodity prices. Byron has received an approved Development Operations Coordination Document (DOCD) for a surface location with a future platform and pipelines on SM70. The Company has submitted a well permit for the first well on SM70 (Golden Trout prospect) and has filed permits for three wells from the SM58 G Platform. Additional permits will be filed as technical reviews are completed. When the EOD 264 is available, Byron currently intends to drill two to three wells. In the event Byron drills three wells, it has the right to drill a fourth well at its sole discretion.

Purchase of Platform

As previously reported, the Company has executed a purchase and sale agreement, at cost of US$ 0.5 million, for a used platform and deck currently located in a construction yard in Abbeville, Louisiana. The deck can be modified to serve as a production platform at several Byron open water leases including the SM70 lease which is planned to be drilled as part of the upcoming drilling program. The deck platform can be modified to hold up to six wells and will require a new support jacket. The facility comes with production equipment, vessels, a crane, and small living quarters which will require refurbishment before being put into service. The purchase of this deck will significantly reduce the cycle time to first production if commercial hydrocarbons are logged at SM70. The platform could also be used at one of Byron's other South Marsh Island projects should that be required.

Properties

As at 31 December 2022, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, USA comprised: -

Properties	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km²)
South Marsh Island Block 71	Byron	50.00/40.625	Production	12.16
South Marsh Island Block 60	Byron	100.00/87.50	June 2024	20.23
South Marsh Island Block 61	Byron	100.00/87.50	September 2027	20.23
South Marsh Island Block 58 (Excl. E1 well)	Byron	100.00/83.33**	Production	20.23
South Marsh Island Block 58 (E1 well in S ½ of SE ¼ of SE ¼ and associated production infrastructure in NE ¼ of NE ¼ of SM69)	W&T Offshore (as successor to ANKOR)	53.00/44.167		
South Marsh Island Block 69 (NE ¼ of NE ¼) (E-2 well)	Byron	100.00/77.33-80.33	Production	1.3
South Marsh Island Block 66	Byron	100.00/87.50	December 2025	20.23
South Marsh Island Block 70	Byron	100.00/87.50	July 2023	22.13
Main Pass Block 293	Byron	100.00/87.50	October 2023	18.46
Main Pass Block 305	Byron	100.00/87.50	October 2023	20.23
Main Pass Block 306	Byron	100.00/87.50	October 2023	20.23

** Working Interest ("WI") and Net Revenue Interest ("NRI").*

*** 100.00% WI to a depth of 13,639 feet TVD and 50% WI below 13,639 feet TVD*

Glossary

1P = Proved Reserves
2P = Proved and Probable Reserves
3P = Proved, Probable and Possible Reserves
Bbl = barrels
bcf = billion cubic feet
Bcfg = billion cubic feet gas
Bopd = barrels of oil per day
Bcpd = barrels of condensate per day
btu = British Thermal Units
mcfg = thousand cubic of gas
mcfgpd = thousand cubic feet of gas per day
Mmcfgpd = million cubic feet of gas per day
mcf = thousand cubic feet
mmcf = million cubic feet
mmbtu = million British Thermal Units
Mbo = thousand barrels of oil
Mmbo = million barrels of oil
NGL = Natural gas Liquids, such as ethane, propane and butane
Psi= pounds per square inch
Tcf = trillion cubic feet

Conversions

6:1 BOE conversion ratio for gas to oil; 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

1 mcfg equals approximately 1.10 btu's currently for SM71 / SM58 production; the heat content of SM71 / SM58 gas may vary over time.

Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity

Byron Energy Limited

ABN	*Quarter ended ("current quarter")*
88 113 436 141	31 December 2022

	Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (6 months) US$'000**
1.	**Cash flows from operating activities**			
1.1	Receipts from customers		16,278	35,050
1.2	Payments for			
	(a)	exploration & evaluation	(63)	(89)
	(b)	development	(10,788)	(30,250)
	(c)	production	(1,962)	(3,296)
	(d)	staff costs	(820)	(1,646)
	(e)	administration and corporate costs	(395)	(1,167)
1.3	Dividends received (see note 3)		-	-
1.4	Interest received		1	3
1.5	Interest and other costs of finance paid		(129)	(380)
1.6	Income taxes paid		-	-
1.7	Government grants and tax incentives		-	-
1.8	Other (provide details if material)			
	- Cash Contributions from JV partners		171	913
	- Oil revenue prepayments (net)		(3,000)	(4,375)
1.9	**Net cash from / (used in) operating activities**		**(707)**	**(5,237)**

2.	**Cash flows from investing activities**			
2.1	Payments to acquire or for:			
	(a)	entities		
	(b)	tenements		
	(c)	property, plant and equipment		
	(d)	exploration & evaluation	(361)	(1,310)
	(e)	investments		

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (6 months) US$'000**
	(f) other non-current assets		
2.2	Proceeds from the disposal of:		
	(a) entities		
	(b) tenements		
	(c) property, plant and equipment		
	(d) investments		
	(e) other non-current assets		
2.3	Cash flows from loans to other entities		
2.4	Dividends received (see note 3)		
2.5	Other (provide details if material)		
2.6	**Net cash from / (used in) investing activities**	**(361)**	**(1,310)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)		
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options / interest free loan repayments		
3.4	Transaction costs related to issues of equity securities or convertible debt securities		
3.5	Proceeds from borrowings		
3.6	Repayment of borrowings	(1,970)	(4,830)
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (provide details if material)		
3.10	**Net cash from / (used in) financing activities**	**(1,970)**	**(4,830)**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	5,750	14,087
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(707)	(5,237)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(361)	(1,310)
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(1,970)	(4,830)

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (6 months) US$'000**
4.5	Effect of movement in exchange rates on cash held	2	4
4.6	**Cash and cash equivalents at end of period**	**2,714**	**2,714**

5.	***Reconciliation of cash and cash equivalents*** *at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts*	**Current quarter US$'000**	**Previous quarter US$'000**
5.1	Bank balances	2,714	5,750
5.2	Call deposits		
5.3	Bank overdrafts		
5.4	Other (provide details)		
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**2,714**	**5,750**

6.	***Payments to related parties of the entity and their associates***	**Current quarter US$'000**
6.1	*Aggregate amount of payments to related parties and their associates included in item 1	454
6.2	Aggregate amount of payments to related parties and their associates included in item 2	

Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.

*Payments to directors comprise: (i) Non-executive directors' fees of A$ 41, (ii) Executive directors' salaries and service fees of US$ 237k and A$ 174k, and (iii) quarterly interest payments of US$ 48k and A$ 44k to certain directors on the loan facilities listed in 7.1a.

7.	*Financing facilities* *Note: the term "facility' includes all forms of financing arrangements available to the entity.* *Add notes as necessary for an understanding of the sources of finance available to the entity.*	**Total facility amount at quarter end $'000**	**Amount drawn at quarter end $'000**
7.1a	Loan facilities (unsecured and repayable by 31 March 2024, bearing 10% interest p.a.)	US$ 2,000 & A$ 2,100	US$ 2,000 & A$ 2,100
7.1b	Loan facilities (secured)	-	-
7.2	Credit standby arrangements	-	-
7.3	Other (please specify) Oil revenue prepayment facility*	US$ 6,625	US$ 6,625
7.4	**Total financing facilities**	US$ 8,625 & A$ 2,100	US$ 8,625 & A$ 2,100
7.5	**Unused financing facilities available at quarter end**		-
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well.		
	**Prepaid oil revenue fee of approximately US$ 1.00 a barrel of oil from drawdown date to last repayment. Remaining cash repayments over next four months.*		

8.	*Estimated cash available for future operating activities*	**US$'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	(707)
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(361)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**(1,068)**
8.4	Cash and cash equivalents at quarter end (item 4.6)	2,714
8.5	Unused finance facilities available at quarter end (item 7.5)	-
8.6	**Total available funding (item 8.4 + item 8.5)**	**2,714**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**2.54**

Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.

8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:

8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?

Answer: N/A

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: N/A

8.8.3	Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?
	Answer: N/A
	Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

Compliance statement

1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.

2 This statement gives a true and fair view of the matters disclosed.

Date: 31 January 2023

Authorised by: Board of Directors
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.
2. If this quarterly cash flow report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, *AASB 6: Exploration for and Evaluation of Mineral Resources* and *AASB 107: Statement of Cash Flows* apply to this report. If this quarterly cash flow report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [*name of board committee – eg Audit and Risk Committee*]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.