BYRONENERGY LIMITED

Quarterly Report for the Period Ended 30 September 2023

Summary

- Byron generated quarterly net sales revenue for the September 2023 quarter of approximately US$8.4 million (92% oil and 8% natural gas), down approximately 11% on the June 2023 quarter of US$9.4 million due to lower production volumes primarily related to third party oil pipeline shut in (SM71) and drilling related shut ins (SM58) partly offset by higher realised oil and gas prices;

- Byron's share of oil and gas production (net sales volume) for the September 2023 quarter was 99,566 barrels of oil and 237,934 mmbtu of gas compared to the previous quarter of 122,008 barrels of oil and 316,096 mmbtu of gas. Lower oil and gas production for the September quarter was due to lower SM71 F Platform and SM58 G Platform production due to a 3 week Crescent oil pipeline maintenance shut in and drilling related shut ins respectively;

- Realised net prices of US$ 77.44 per barrel of oil and US$ 2.42 per mmbtu of natural gas net to Byron after quality adjustments, oil and gas transportation charges and royalties were achieved during the September quarter (June 2023 quarter: net realised prices of US$ 71.08 per barrel of oil and US$ 2.12 per mmbtu of natural gas);

- During the September 2023 quarter, Byron made an initial draw of US$10.0 million under the new $US 22.0 million Oil Prepayment Facility; and

- SM58 G4 and G6 wells commenced drilling during the September quarter; subsequent to end of the quarter Byron announced that both wells had logged hydrocarbon pay and will be completed for production, with production expected to commence in mid Q4 2023.

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 30 Sep 2023:	**1,081.4 million**
Quoted shares:	**1,081.4 million**
Options on issue (unquoted):	**2.0 million**
Cash at Bank 30 Sep 2023:	**US$16.9 million**
Borrowings 30 Sep 2023:	**US$3.4 million**
Revenue prepayment 30 Sep 2023:	**US$10.0 million**
Market Capitalisation at 30 Sep 2023:	**A$93 million (@A$0.086 per share)**

Directors
Doug Battersby (Non-Executive Chairman)
Maynard Smith (Chief Executive Officer)
Prent Kallenberger (Chief Operating Officer)
Charles Sands (Non-Executive Director)

Directors (continued)
Paul Young (Non-Executive Director)
William Sack (Executive Director)
Company Secretary and Chief Financial Officer
Nick Filipovic

Level 4 480 Collins Street Melbourne VIC 3000 T: 03 8610 6583 F: 03 8610 6334 E: info@byronenergy.com.au W: byronenergy.com.au

ABN 88 113 436 141

BYRONENERGY LIMITED

Corporate

Issued Capital

As at 30 September 2023, 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

Borrowings and oil revenue prepayment

As at 30 September 2023, Byron's outstanding loans comprised:-

Lender	US$ M	A$ M	30 September 2023 US$ equivalent (@A$1=US$0.6458)	30 June 2023 US$ equivalent (@A$1=US$0.6630)
Directors	2.00	1.75	3.13	3.16
Shareholder	-	0.35	0.23	0.23
Total	**2.00**	**2.10**	**3.36***	**3.39***

*as at 30 September 2023, Byron also had US$ 1.5 million in insurance premium financing outstanding

Directors' and Shareholder Loans

Byron's outstanding loans of approximately US$ 3.36 million as of 30 September 2023, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder. These loans are due to be repaid by 31 December 2025.

Oil Revenue Prepayment

In August 2023, the Company's oil purchaser provided access to further funding of US$22.0 million (Oil Prepayment Facility) primarily to fund the SM58 development drilling & completion program.

Key terms of the Oil Prepayment Facility include:-

(i) Extension of Byron's existing oil offtake agreement through December 2026, with the oil super-major, the sole purchaser of Byron's oil production and hedge counterparty since inception;

(ii) a 24-month total term starting upon the initial draw of US$10 million (Initial Draw) taken on 14 September, 2023, a second optional draw of up to US$12 million (Second Draw) within 90 days of the first and includes a 6-month interest only grace period followed by eighteen equal monthly repayment instalments;

(iii) the fee for the initial US$10 million prepayment will be charged at US$1.27 per produced barrel of oil (bo) delivered to the counterparty on a fixed volume of oil of 1.606 million bo during the term of the Oil Prepayment Facility;

(iv) a hedge of approximately 500 barrels of oil per day (bopd) at a minimum average price of US$68.00/bo over the term of Oil Prepayment Facility, subsequently reduced to 475 bopd as Byron was able to hedge at a higher average price of US$74.68/bo;

(v) the Second Draw of up to US$12 million is optional, contingent on mutually agreed success, and if

Corporate (cont.)

drawn has an associated fee of up to US$1.39 bo;

(vi) a contingent additional hedge component of approximately 200 bopd at a minimum price of US$69.0/bo for a period of 6 months to be placed prior to the Second Draw; and;

(vii) The Oil Prepayment Facility is secured by an industry standard mortgage and security agreement over Byron's assets and is guaranteed by Byron and its subsidiaries; the per barrel fee arrangement equates to approximately a 15% pa interest rate over the facility period.

For additional information refer to the Company's ASX releases dated 1 August 2023 and 15 September 2023.

Oil price hedging

Under the Oil Prepayment Facility, referred to above, Byron was required as a condition precedent to hedge approximately 475 bopd of working interest oil production for a period of 24 months prior to the Initial Draw. Byron, prior to taking the Second Draw, would also be required to hedge the equivalent of approximately 200 bopd working Interest (WI) level at a minimum price of $69/bo for a period of 6 months. It should be noted that these hedging requirements are expressed in WI barrels under the Oil Prepayment Facility as the counterparty contracts to buy all Byron controlled barrels comprising those barrels sold on behalf of the royalty owners (Federal government) as well as Byron. For clarity, the First and Second draw hedge requirements, if expressed in Byron's Net revenue Interest (NRI), for purposes such as determining a share of net production or resultant net revenue, is approximately 395 net bo and 165 net bo respectively using an average NRI of 83%.

Under the Oil Prepayment Facility, Byron also has the option to place additional financial or derivative hedging with the counterparty to either capture upside above the forward sale hedges or to protect additional Byron NRI barrels against potentially declining oil prices. These financial or derivative hedges are conventionally expressed in NRI or net barrels to Byron.

Consequently, Byron's realised prices for oil may at any time be a combination of hedged and unhedged volumes. The Company's current oil hedging position comprises:-

(i) the Forward Sale Agreement (FSA), which specifies a price per physical barrel in advance for each delivery period during the term of the contract, and

(ii) a financial (derivative) hedge in the form of a put option which provides the buyer (Byron) of the option with a hedge against potentially declining oil prices.

The hedging counterparty, for both the FSA and the oil put options, 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 is as follows: -

Period	Daily Hedged WI Volume (bopd)	Period Hedged WI Volume (bbl)	Daily Hedged NRI Volume (bopd)	Period Hedged NRI Volume (bbl)**	NYMEX WTI Fixed Base Price Crude Oil*
FSA Hedge 1 Sept 2023- 30 August 2025 (entered into during September 2023 quarter)	250	182,750	208	151,683	US$74.68
FSA Hedge 2 October 2023- 30 August 2025 (entered into during the September 2023 quarter)	225	157,725	187	130,911	US$75.12
Put options October 2023 - December 2023 (entered into in October 2023)	N/A	N/A	300	27,600	US$80.00

*West Texas Intermediate (WTI) fixed base price is then adjusted for NYMEX Roll, LLS/WTI price differentials, Transportation (estimated at -US$5.70/ barrel +-0.20) to arrive at a realised price; the fixed price per barrel under the FSA qualifies for purposes of royalty calculations

**The actual NRI volume will depend on weighted average production from SM58 G and SM71 F platforms

Corporate (cont.)

Cashflow

Byron generated receipts from customers of approximately US$ 8.7 million during the September 2023 quarter, compared to US$ 10.4 million for the June 2023 quarter. After deducting payments for production (lease operating expenses) net receipts from production were US$ 6.7 million for the quarter, a decrease of US$1.2 million from the previous quarter. After deducting payments for development and other operating activities of US$3.8 million and adding the drawdown of US$10.0 million in oil revenue prepayments, the net cash inflow from operating activities was US$12.9. Byron ended the September 2023 quarter with a cash balance of US$16.9 million, an improvement of US$12.7 million over the 30 June 2023 balance.

Consolidated statement of cash flows (US$ million)	Sep 23 quarter	Jun 23 quarter
Cashflow from operating activities		
Receipts from customers	8.7	10.4
Payments for production	-2.0	-2.5
Net receipts from production	**6.7**	**7.9**
Payment for development	-2.0	-1.1
Payments for other operating activities (net)	**-1.8**	**-2.7**
Oil revenue pre-payment / (repayment)	**10.0**	**-1.7**
Net cash from / (used in) operating activities	**12.9**	**2.4**
Cash flows from investing activities		
Exploration and evaluation	**-0.2**	**-1.2**
Net cash from / (used in) investing activities	**-0.2**	**-1.2**
Cash flows from financing activities		
Net cash from / (used in) financing activities	**-**	**-**
Net increase / (decrease) in cash and cash equivalents for the period	**12.7**	**1.2**
Cash and cash equivalents at end of quarter	**16.9**	**4.2**

For further details on the September 2023 quarter cashflows refer to Appendix 5B.

Oil and Gas Production/Sales

Byron's share of oil and gas production and sales for the September 2023 quarter and financial year to date is summarised in the table below.

Production (sales)	Sep 2023 quarter	Jun 2023 quarter	Year to date 30 Sep 2023 (3 months)	Year to date 30 Sep 2022 (3 months)
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	27,739	42,209	27,739	75,572
Gas (mmbtu)	31,896	43,297	31,896	59,499
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	68,374	75,714	68,374	95,938
Gas (mmbtu)	205,763	271,924	205,763	452,265
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	3,453	4,085	3,453	4,650
Gas (mmbtu)	276	875	276	587
Total Net production (NRI basis)				
Oil (bbls)	**99,566**	**122,008**	**99,566**	**176,160**
Gas (mmbtu)	**237,934**	**316,096**	**237,934**	**512,351**

Aggregate oil and gas production and sales, net to Byron, were 99,566 bbls of oil and 237,934 mmbtu of gas for the September 2023 quarter compared to 122,008 bbls of oil and 316,096 mmbtu of gas for the June 2023 quarter. Oil production and sales for the September 2023 quarter were below the June quarter due to lower SM71 oil and gas production, mainly as a result of an oil sales pipeline shut in for repairs, and lower SM58 production, mainly due to drilling rig downtime (drilling of G4 and G6 wells) and compressor downtime.

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

Sale revenue (accrual basis) US$ million	Sep 2023 quarter	Jun 2023 quarter	Year to date 30 Sep 2023	Year to date 30 Sep 2022
Net sales revenue (Byron share on NRI basis)	8.4	9.4	8.4	19.2

Net sales revenue for the September 2023 quarter was approximately US$ 8.4 million (92% oil and 8% natural gas) after quality adjustments, oil transportation charges and royalties, and down approximately 11% compared to US$ 9.4 million for the prior quarter. Net sales revenue was lower for the September 2023 quarter, compared to the June 2023 quarter, mainly due to lower oil and gas production partly offset by higher realised oil and gas prices.

For the September 2023 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$ 77.44 per bbl (US$ 83.15 excluding transportation) compared to US$ 71.08 per bbl and US$ 76.07 per bbl respectively for the June 2023 quarter.

During September 2023 quarter the West Texas Intermediate oil price traded in the range of US$69.71/bbl to

Oil and Gas Production/Sales (cont.)

US$93.67/bbl. Prices increased over the quarter mainly due to extension of production cuts by OPEC+ leaders, Saudi Arabia and Russia.

Byron realised an average gas price after transportation deductions of approximately US$ 2.42 per mmbtu for the September 2023 quarter (US$ 2.79 excluding transportation) compared to US$ 2.12 per mmbtu and US$ 2.48 per mmbtu respectively for the June 2023 quarter.

U.S. natural gas prices closed the September 2023 quarter at US$ 2.93 approximately 5% above the June 2023 close of US$2.80. Rising output and mostly mild weather continued to keep demand low and allow utilities to leave more gas in storage than usual.

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.

As of 30 September 2023, the SM71 F facility has produced approximately 4.7 million barrels of oil (Mmbo) (gross) since initial production began. The facility has also produced approximately 5.6 billion cubic feet of gas (Bcfg) (gross).

Total September 2023 quarter gross sales volumes for all wells on the SM71 F Platform totalled approximately 68,079 barrels of oil and 78,432 mmbtu of gas (June 2023 quarter, 101,303 barrels and 83,901 mmbtu). Lower production from SM71 F Platform for the September quarter was mainly due to shut in of production for approximately three weeks in September as a result of repairs to the Crimson oil sales pipeline. SM71 F platform returned to production in late September.

Water cut from the SM71 F3 well continued to increase (averaged approximately 80% water cut for the September quarter compared to approximately 72% for the June 2023 quarter). The updip SM71 F1 well continues to produce water free and the rate will continue to be managed to optimize the D5 Sand reservoir's oil production.

Project Updates (cont)

The SM71 F2 and F4 wells produce from the J1 Sand.

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 are above 13,639 feet subsea.

Byron also holds an interest in the SM69 E2 well under the Joint Exploration Agreement (JEA) with W&T Offshore, Inc. (W&T Offshore). As previously reported, Byron's 100% Working Interest (WI) and 80.33% Net Revenue Interest (NRI) in the SM69 E2 well reduced during the March quarter to 70% WI with an unburdened 58.33% NRI, effective 1 January, 2023, after WT Offshore exercised its option to convert its overriding royalty interest into a working interest in the E2 well.

Water depth in the area is approximately 132 feet.

As of 30 September 2023, the SM58 G facility has produced approximately 8.6 Bcfg and 0.8 million barrels of oil and condensate (gross) on a cumulative basis from five wells (G1, G2, G3, G5 and E2).

SM58 G Wells Production:

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 approximately 340 bopd and no formation water. Gas 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 G5 well will be recompleted in either the K4 or N2 sand with coil tubing after the Enterprise Offshore Drilling rig leaves the SM58 G platform, following completion of the SM58 G4 and G6 wells.

SM69 E2 Well:

The SM69 E2 well produces from the K4/B65 Sand. During the September 2023 quarter, the SM69 E2 well production has remained relatively steady with no water production, exceeding Byron's initial water arrival expectations. The E2 well produced at an average gross daily rate of 597 bopd and 0.323 MMcfgpd (348 bopd and 0.189 Mmcfgpd net to Byron's interest) during the September 2023 quarter. Byron continues to manage the well production rates to achieve optimal oil and gas recovery.

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. Under the JEA, Byron will continue to process the production at SM58 G Facility on behalf of the joint interest under a forthcoming Production Handling Agreement with the non-operating partner paying Byron for the processing and transportation of production.

As reported on 28 February 2023, effective 1 January 2023 the E2 well reached Project Payout, having realised more than US$22 million of net revenue against total project expenses, and W&T Offshore has elected to convert its 3% overriding royalty interest in the E2 well into a 30% WI and 24.99% NRI Byron with an unburdened 70% WI and 58.33% NRI.

Total quarterly gross sales volumes for all wells, including E2, on the SM58 G Platform, totalled 256,685 mmbtu

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

of gas and 98,426 barrels of oil for the September 2023 quarter (June 2023 quarter 341,441 mmbtu of gas and 109,349 barrels of oil). Lower production was due to a combination of drilling rig downtime (drilling of G4 and G6 wells) and compressor downtime.

SM58 G4 and G6 Development Wells:

The Enterprise Offshore Drilling 264 (EOD 264) commenced drilling of SM58 G4 (G4) and the SM58 G6 (G6) wells, the Tiger Trout and Gila Trout prospects respectively in mid-August 2023. As a cost savings measure, the two wells were batch drilled.

The G4 well reached a final total depth of 10,169 feet measured depth (MD)/9,017 true vertical depth (TVD) on 25 September 2023 (USCDT), having successfully drilled the Tiger Trout prospect. Initial Log While Drilling (LWD) gamma ray/resistivity logs identified likely oil pay in the primary K4(B65) Sand target interval with preliminary pay counts totalling 82 measured depth feet (59 feet True Vertical Thickness) of oil across the K4 Sand. A cased hole PNL porosity log has since been obtained confirming the presence of oil-bearing pay in the K4 Sand.

The G6 well logged two likely oil sands, in the I0 Sand and the L2 Sand. A primary objective, the N2 Sand was logged as a silty, tight interval. While running 7 5/8" production casing to bottom, the casing became stuck above the L2 Sand preventing it from being completed in this wellbore. At that time, Byron decided to skid the rig to the G4 well which was successfully drilled to a total depth of 10,169 feet MD 9,017 feet TVD and production casing was run through the K4 sand (refer to the ASX announcement of 25 September 2023).

Given that casing did not reach the L2 Sand, Byron decided to set a whipstock in the casing at 8,700 feet MD and sidetrack to drill the G6 Bypass (G6 BP01) well.

The G6 BP01 reached final total depth of 10,575 feet MD/8,974 feet TVD on 30 September (USCDT). LWD Gamma Ray and Resistivity tools have confirmed the presence of 24 feet True Vertical Thickness (TVT) of likely oil pay in the L2 Sand and 78 feet of TVT hydrocarbon pay in the N2 Sand. Additionally, mud log analysis of both sands indicated the presence of oil in the cuttings along with the heavier gasses usually indicative of oil.

The G6 BP01 drilled the L2 Sand 30 feet down dip of the original G6 intersection and resulted in what appears to be a full column of oil. Mud log descriptions of the L2 Sand indicate it is a fine grained, well sorted sand with excellent porosity while also exhibiting dull yellow fluorescence across the entire interval along with heavy gasses indicative of oil pay. Resistivity readings from the LWD logs are consistent with the oil leg logged in the original hole.

The N2 Sand intersected a 78 feet TVT column of hydrocarbon within a very high-quality channel sand with a possible oil/gas contact. The G6 BP01 well N2 intersection was approximately 300 feet (90 meters) away from the G6 original hole N2 intersection. The N2 Sand mud log in the G6 Bypass indicates it is a medium to fine grained, well sorted sand with excellent porosity and also exhibiting dull yellow fluorescence across the entire interval along with moderately heavy gasses present which is commonly indicative of oil pay. However, the electric logs show more resistivity at the top of the sand than is typically associated with oil suggesting a gas/oil contact about 20 feet from the bottom of the sand. The G6 BP01 N2 Sand intersection is also 800 feet up dip of the SM58 B12 well which produced 1.4 million barrels of oil with a strong water drive.

G4 completion work concluded in late October 2023 with production hook up work underway. At the date of this report G6 completion operations are underway. Production from the G4 and G6 wells is expected to commence in mid Q4 2023.

Project Updates (cont)

(b) South Marsh Island SM58 E1 well, SM69 E Platform

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with two active producing wells, the SM58 E1 and E2 wells. 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 September 2023 quarterly net sales volumes for the SM58 E1 well totalled 3,453 barrels of oil and 276 mmbtu (June 2023 quarter 4,085 barrels of oil and 875 mmbtu).

W&T Offshore, Inc is the designated operator of this well and 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.

Properties

As at 30 September 2023, 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 (Km^2)
South Marsh Island Block 71	Byron	50.00/40.625	Production	12.16
South Marsh Island Block 57	Byron	100.00/81.25	April 2028	21.98
South Marsh Island Block 61	Byron	100.00/87.50	September 2027	20.23
South Marsh Island Block 58 (Excl. E1 well) 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)	Byron W&T Offshore	100.00/83.33** 53.00/44.167	Production	20.23
South Marsh Island Block 69 (NE ¼ of NE ¼)	Byron	100.00/70.00-58.33***	Production	1.3
South Marsh Island Block 66	Byron	100.00/87.50	December 2025	20.23
Grand Isle 63	Byron	100.00/81.25	April 2028	20.23
Grand Isle 72	Byron	100.00/81.25	April 2028	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.*

**** Effective 1 January 2023 Byron's 100% WI and 80.33% NRI in the SM69 E2 well reduced to 70% WI with an unburdened 58.33% NRI, after WT Offshore exercised its option to convert its overriding royalty interest into a 30% working interest in the E2 well which achieved payout in December 2022.*

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
Bo = barrel of oil
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	30 September 2023

	Consolidated statement of cash flows	**Current quarter US$'000**	**Year to date (3 months) US$'000**
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	8,685	8,685
1.2	Payments for		
	(a) exploration & evaluation	(36)	(36)
	(b) development	(1,951)	(1,951)
	(c) production	(1,999)	(1,999)
	(d) staff costs	(939)	(939)
	(e) administration and corporate costs	(1,023)	(1,023)
1.3	Dividends received (see note 3)		
1.4	Interest received	7	7
1.5	Interest and other costs of finance paid	(116)	(116)
1.6	Income taxes paid		
1.7	Government grants and tax incentives		
1.8	Other (provide details if material)		
	- Cash Contributions (refunds) from (to) JV partners	235	235
	- Refundable security deposits	-	-
	- Oil revenue prepayments (net)	10,000	10,000
1.9	**Net cash from / (used in) operating activities**	**12,863**	**12,863**

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	(223)	(223)

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (3 months) US$'000**
	(e) investments		
	(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**	**(223)**	**(223)**

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	-	-
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**	**-**	**-**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	4,224	4,224
4.2	Net cash from / (used in) operating activities (item 1.9 above)	12,863	12,863
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(223)	(223)

Consolidated statement of cash flows		Current quarter US$'000	Year to date (3 months) US$'000
4.4	Net cash from / (used in) financing activities (item 3.10 above)	-	-
4.5	Effect of movement in exchange rates on cash held	(4)	(4)
4.6	**Cash and cash equivalents at end of period**	**16,860**	**16,860**

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	16,860	4,224
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)**	**16,860**	**4,224**

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	480
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$ 31, (ii) Executive directors' salaries and service fees of US$ 258k and A$ 191k, 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 December 2025, bearing 12% 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 (secured)*	US$ 22,000	US$ 10,000
7.4	**Total financing facilities**	US$ 24,000 & A$ 2,100	US$ 12,000 & A$ 2,100

7.5	**Unused financing facilities available at quarter end***	US$12,000

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.

**Oil prepaid revenue fee for Tranche 1 is US$1.27 a barrel of oil from drawdown date to last repayment and if Tranche 2 is drawdown, an additional US$1.39 a barrel of oil is charged. Repayments don't begin for 6 months and repayments are made in equal instalments from the Company's oil revenue over 18 months with the final repayment made in August 2025.*

8.	***Estimated cash available for future operating activities***	**US$'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	12,863
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(223)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**12,640**
8.4	Cash and cash equivalents at quarter end (item 4.6)	16,860
8.5	Unused finance facilities available at quarter end (item 7.5)	12,000
8.6	**Total available funding (item 8.4 + item 8.5)**	**28,860**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**N/A**

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 October 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.