BYRONENERGY LIMITED

Quarterly Report for the Period Ended 31 March 2021

Summary

- Byron's share of oil and gas production (net sales volume) for the March 2021 quarter was 132,621 barrels of oil and 1,309,513 mmbtu of gas compared to the December 2020 quarter of 111,516 barrels of oil and 1,742,124 mmbtu of gas;

- Net revenue recorded for the March 2021 quarter, was approximately US$11.8 million (net to Byron after quality adjustments, transportation charges and royalties) with realised net prices of US$ 53.71 per barrel of oil and US$ 3.22 per mmbtu of natural gas for the March 2021 quarter (December 2020 quarter: net revenue approximately US$9.2 million with realised net prices of US$ 42.06 per barrel of oil and US$ 2.25 per mmbtu of natural gas);

- Byron appointed Seaport Global Securities to pursue a more flexible debt finance package for the repayment of existing loans and fund multi-well development capital for SM58 area project; and

- Interim reserves report, as at 31 December 2020, was completed during the March 2021 quarter and released to the ASX on 23 February 2021.

Name:	**Byron Energy Limited**
ASX code:	**BYE**
Shares on issue at 31 Mar 2021:	**1,040.3 million**
Quoted shares:	**1,040.3 million**
Options on issue (unquoted):	**41.1 million**
Cash at Bank 31 Mar 2021:	**US$3.1 million**
Borrowings 31 Mar 2021:	**US$20.4 million**
Market Capitalisation at 31 Mar 2021:	**A$130 million (@A$0.125 per share)**

Corporate

Issued Capital

As at 31 March 2021, Byron's issued capital comprised:-

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	1,040,295,102	1,040,295,102	Nil
Options	41,100,000	Nil	41,100,000

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

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ABN 88 113 436 141

Corporate (cont.)

Borrowings

As at 31 March 2021, Byron's outstanding loans comprised:-

Lender	US$ M	A$ M	US$ Equivalent (@A$1=US$0.7602)
Directors	2.00	1.75	3.33
Shareholder	-	0.35	0.27
Crimson Midstream	16.75	-	16.75
Total	**18.75**	**2.10**	**20.35***

* as at 31 March 2021, Byron also had US$ 0.5 million in insurance premium financing outstanding

Crimson Midstream

In December 2020 Crimson agreed that notwithstanding the terms of the Promissory Note the parties agreed that the Production Handling Agreement ("PHA") Fee would be fixed at a discounted rate of US$15/bbl for December 2020, January 2021 and February 2021. In March 2021 the PHA Fee was fixed at the expected undiscounted rate of US$20/bbl for the current PHA Period of March/April/May 2021. The outstanding principal balance of the Crimson note has been reduced to $16.75 million from $18.5 million, as of 31 March 2021.

For further details of the Promissory Note refer to the Company's ASX release dated 4 December 2019.

Directors and Shareholder Loans

Byron's outstanding loans of approximately US$3.6 million as of 31 March 2021, from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a long standing shareholder are due to be repaid on 31 March 2022.

Appointment of Seaport Global

As announced to the ASX on 27 January 2021, Byron has appointed Seaport Global to pursue a more flexible debt finance package for the repayment of existing loans and fund multi-well development capital for SM58 area project. In a further announcement on 31 March 2021 Byron reported that:-

- Together with the assistance of the Company's exclusive US investment banking financial advisors, Seaport Global, Byron was reviewing several term sheets received from interested lenders;
- The goal of the ongoing effort is to secure an attractive, flexible debt finance package to accelerate Byron's SM58 multi-well drilling program; and
- Regardless of the timing or outcome of the refinancing initiative, Byron anticipates being able to drill the SM 69 E2 well in June/July 2021, subject to rig availability.

Working Capital Management

During the March 2021 quarter Byron reduced the balance of trade and other payables from US$11.1 million as at 31 December 2020 to US$3.4 million as at 31 March 2021 through payments for SM58 development expenditure incurred during the December 2020 quarter.

Also during the March 2021 quarter Byron received an oil revenue prepayment of US$3.5 million from the

Corporate (cont.)

Working Capital Management (cont)

hedging counterparty under the existing forward sale agreement described below. The prepayment amount of US$3.5 million will be repaid from oil revenues under the forward sale agreement over four months commencing in May 2021.

Oil Price Hedging

Byron's realised prices for oil are a combination of hedged and unhedged volumes. As at 31 March 2021, the Company's oil hedging position is governed by:-

(a) a forward physical sale agreement ("Forward Sale Agreement"), which specifies a price per barrel in advance for each delivery period during the term of the contract; and

(b) financially settled swaps ("Swaps") which guarantee the price that Byron will receive for the hedged barrels under the Swaps.

The hedging counterparty for the Forward Sale Agreement and the Swaps 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 March 2021 is as follows:-

Period	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-Dec 2021 (Forward Sale Agreement)	450	164,250	US$52.86	unhedged	unhedged	To be determined
Mar-Dec 2021 (Swaps)	200	61,200	US$62.00 (monthly average)	unhedged	unhedged	To be determined
Jan-Dec 2022 (Forward Sale Agreement)	400	146,000	US$52.70	unhedged	unhedged	To be determined

*WTI CMA base price is adjusted for NYMEX Roll, LLS/WTI price differentials. Transportation (estimated at -US$4.70/barrel +-0.20) to arrive at a realised price.

For additional information on the Company's oil price hedging activities, refer to ASX releases dated 22 April 2020, 18 June 2020 and 8 March 2021.

Oil and Gas Production/Sales

Byron's share of oil and gas production and sales for the March 2021 quarter is summarised in the table below.

Production (sales)	Mar 2021 quarter	Dec 2020 quarter	YTD 31 Mar 2021	YTD 31 Mar 2020
Net production (Byron share (NRI basis) SM71				
Oil (bbls)	92,277	89,522	273,559	294,656
Gas (mmbtu)	77,940	71,412	312,750	482,270
Net production (Byron share (NRI basis) SM58				
Oil (bbls)	34,507	21,004	60,464	N/A
Gas (mmbtu)	1,231,137	1,670,316	3,266,742	N/A
Net production (Byron share (NRI basis) SM58 E1 well				
Oil (bbls)	5,838	990	9,395	14,058
Gas (mmbtu)	437	396	1,705	3,036
Total Net production (NRI basis)				
Oil (bbls)	132,621	111,516	343,417	308,714
Gas (mmbtu)	1,309,513	1,742,124	3,581,197	485,306

Aggregate oil and gas production and sales, net to Byron, was 132,621 bbls of oil and 1,309,513 mmbtu of gas for the March 2021 quarter compared to 111,516 bbls of oil and 1,742,124 mmbtu of gas for the December 2020 quarter.

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

Sale revenue (accrual basis) US$ million	Mar 2021 quarter	Dec 2020 quarter	YTD 31 Mar 2021	YTD 31 Mar 2020
Net sales revenue (Byron share on NRI basis)	11.8	9.2	26.1	17.6

Net sales revenue for the March 2021 quarter was US$11.8 million compared to US$9.2 million for the December 2020 quarter. Net sales revenue was higher during the March 2021 quarter due to higher realised oil and gas prices during the March 2021 quarter and higher oil production partly offset by lower gas production.

For the March 2021 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$ 53.71 per bbl (US$ 58.28 excluding transportation) compared to US$ 42.06 per bbl and US$ 46.62 per bbl respectively for the December 2020 quarter.

Byron realised an average gas price after transportation deductions of approximately US$ 3.22 per mmbtu for the March 2021 quarter (US$ 3.56 excluding transportation) compared to US$ 2.25 per mmbtu and US$ 2.59 per mmbtu respectively for the December 2020 quarter.

Collarini Interim Reserve Report as at 31 December 2020

As part of the debt refinancing initiative Byron was required to complete an interim reserve report.

The 31 December 2020 reserves update was focussed on the Company operated producing properties, South Marsh Island Block 71 ('SM71") and South Marsh Island Block 58 ("SM58") to assist with the refinancing initiative, as announced to the ASX on 27 January 2021. The revised reserves and resources for SM71 and SM58 are discussed in the Company's ASX release dated 23 February 2021. There have been no material changes in the reserves and/or prospective resources for the Company's other properties, as reported to the ASX on 10 September 2020.

Combined reserves and resources as of 31 December 2020 for all Byron leases are captured in the following table:

Byron Energy Limited - Total Reserves and Resources Gulf of Mexico, Offshore Louisiana, USA				
Remaining as at 31 December 2020	Gross		Net	
	Oil Mmbbl	Gas Bcf	Oil Mmbbl	Gas Bcf
Reserves (developed and undeveloped)				
Proved (1P)	**13,073**	**69,666**	**7,932**	**57,273**
Probable Reserves	10,533	52,815	7,663	44,677
Proved and Probable (2P)	**23,606**	**122,481**	**15,595**	**101,950**
Possible Reserves	12,877	32,817	9,737	27,416
Proved, Probable & Possible (3P)	**36,483**	**155,298**	**25,332**	**129,366**
Total Prospective Resources Best Estimate (unrisked)	**49,890**	**753,350**	**40,425**	**623,583**

For additional information on the Company's 31 December 2020 interim reserves and resources, refer to Byron's ASX release dated 23 February 2021.

***Reserves** - The aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation.*

***Prospective Resource** - The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon.*

Project Updates

Salt Dome Projects

1. 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

Project Updates

South Marsh Island 73 Salt Dome (cont)

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. Refer to Attachment 1 for Byron's areas of interest around the SM73 field.

(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, successfully drilled and completed in March 2020, commenced production in in mid-March 2020 until it was shut in September 2020.

The F1 and F3 wells are producing in the primary D5 Sand reservoir and the F2 well is producing from the B55 Sand.

As of 31 March 2021, the SM71 F facility has produced approximately 3.11 million barrels of oil ("Mmbo") (gross) since initial production began. The facility has also produced approximately 4.0 billion cubic feet of gas ("Bcf") (gross). The SM71 lease ranks number 3 of all Gulf of Mexico currently active oil producing leases on the US Gulf of Mexico shelf with the SM71 F3 and F1 ranked as the number 1 and number 2 active oil producing wells. The D5 Sand completions in the SM71 F1 and F3 wells have total gross oil production of just over 3 Mmbo.

Total quarterly gross sales volumes for all wells on the SM71 F Platform totalled 227,069 barrels of oil and 191,852 mmbtu's with only minor amounts of water produced by the SM71 F2. The F1 an F3 continue to produce water-free from the D5 Sand. Production from the SM71 F Platform was slightly below expected production primarily due to compressor maintenance issues in late February.

Based on a 90 day quarter, gross oil and gas production at SM71 for the March quarter 2021 equated to daily rates of approximately 2,523 barrels of oil and 2,132 mmbtu's of gas.

(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 are above 13,639 feet subsea.

Water depth in the area is approximately 132 feet.

Gas and oil production from the Byron Energy SM58 G platform was initiated on 7 September 2020 when the SM58 G1 well was opened to sales.

As of 31 March 2021, the SM58 G facility has produced approximately 3.5 Bcf and 74,000 barrels of oil and

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

(b) South Marsh Island 58 (cont)

condensate (gross) since initial production began. The SM58 lease ranks number 4 of all currently active gas producing leases on the US Gulf of Mexico shelf with the SM58 G1 ranked as the number 4 active gas producing well.

The SM58 G1 well produces from the Upper O Sand and as of 31 March 2021 has produced a gross total of approximately 2.9 Bcf of gas, 38,000 barrels of consistent 56.5-degree gravity condensate and no formation water. The SM58 G2ST well was tied into the SM58 G Platform and the O Sand was opened to production on 29 October 2020 and has now produced approximately 0.6 billion cubic feet of gas and 36,000 barrels of oil with some completion fluids and formation water.

Total quarterly gross sales volumes for all wells on the SM58 G Platform totalled 1.3 Bcf of gas and 41,410 barrels of oil. Production from the SM58 G Platform for the March 2021 quarter was negatively impacted by facility maintenance and downtime in early February.

Based on a 90 day quarter, gross oil and gas production at SM58 for the March quarter 2021 equated to daily rates of approximately 460 barrels of oil and 16,415 mmbtu's of gas.

(c) South Marsh Island 57

Byron holds a 100% WI and an 81.25% NRI in SM57. Water depth in the area is approximately 125 feet.

The SM57 block, as part of the larger SM71 project area, is also a focus area of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

(d) South Marsh Island 59

Byron holds a 100% WI and an 81.25% NRI in SM59. Water depth in the area is approximately 125 feet.

The SM59 block, as part of the larger SM71 project area, is also focus areas of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

(e) South Marsh Island SM58 E1 well, SM 69 E Platform and proposed E2 well

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 630,000 barrels of oil, 0.185 bcf of gas and 800,000 barrels of formation water before the well was recompleted in the March quarter.

In January 2021, the SM58 E1 was recompleted during the March 2021 quarter, by sliding a sleeve covering the existing perforations in the K4 Sand and opening those across the K Sand (B55 Sand), a completion which also benefits from sand control. Because the wellbore completion work was already in place, the cost of recompletion was less than US$60,000 net to Byron.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

Total quarterly gross sales volumes for the SM58 E1 well totalled 13,217 barrels of oil, 989 mmbtu's and 5,600 barrels of water. Production from the SM58 E1 well is in line with the Company's expectations.

Ankor Energy, LLC ("ANKOR") 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.

Byron also holds a farm-in right under the Joint Exploration Agreement ("JEA") with ANKOR group which provides for the drilling of a SM 69 E2 exploration well to be operated by Byron.

By funding 100% of the SM69 E2 well Byron can earn 100% WI and 80.33% NRI until E2 Project Payout, at which time and at the leaseholder's election, Byron's NRI would 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 (equivalent to 83.33% 8/8ths).

The SM69 E2 wellbore is planned to a depth of approximately 8,750 feet MD (8,120 feet TVD). This fault block is interpreted to be an up-dip pool potentially fault separated from analogous production in the immediately adjacent fault block "A" on SM58. Fault block A has to date produced a combined gross total of approximately 3.4 Mmbo and 4.3 Bcfg from two wellbores completed in zones equivalent to these 6 target sands. The primary target of the E2 well, the B65 (K4) Sand has, to date, produced approximately 13 Mmbo in the SM73 Field.

If the SM69 E2 well is drilled and is successful Byron would produce it back to the SM58 G platform through a new pipeline laid in July 2020. Hydrocarbons, if any, from the E2 well would be processed and sold through the SM58 G Platform.

For additional information of the SM69 E2 project, refer to the Company's ASX releases dated 1 April 2019 and 17 June 2020.

(f) South Marsh Island 60

Byron Energy Inc, a wholly owned subsidiary of the Company, acquired the South Marsh Island 60 lease ("SM60") at the Gulf of Mexico, Outer Continental Shelf ("OCS") Lease Sale 252 held in New Orleans, Louisiana on 20 March 2019.

From 1978 through 2006, nine wells completed for production on SM60 produced a combined total of 385 billion cubic feet of gas and 787,000 barrels of oil. SM60 lies within the area of Byron's RTM reprocessing project which was used to evaluate the prospect potential on the block.

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) in SM 60.

(g) South Marsh Island 70

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) South Marsh Island 70 ("SM 70").

SM70 lies within the area of Byron's RTM reprocessing project.

(h) South Marsh Island 66

Byron Energy Inc., a wholly owned subsidiary of the Company, acquired the South Marsh Island 66 lease ("SM66") at the Gulf of Mexico OCS Lease Sale 256 held on 18 November 2020.

Project Updates (cont)

South Marsh Island 73 Salt Dome (cont)

Byron has a 100% WI and an 87.50% NRI in the block.

SM66 was evaluated using the same reprocessed Reverse Time Migrated seismic data used to make the discoveries on SM71 and SM58. Historical production from SM66 has totalled 1.4 million barrels of oil and 238 billion cubic feet of gas from 1969 to 2018.

SM66 lease enhances the Company's prospect inventory and is a block expected to move up in Byron's drilling program as it is considered to have significant hydrocarbon potential.

(i) South Marsh Island Area permitting status

Byron has spent considerable time pursuing key regulatory permits in the South Marsh Island Project Area. Executive Order 3395 went into effect on 20 January 2021 and has had no material effect on the process for permits on existing leases. Byron was granted approval for a revised Development Operations Coordination Document ("DOCD") on 10 February 2021 which allows the use of slots G5 through G9 from the South Marsh 58 G Platform. Byron has submitted DOCD permits for wells on SM57, SM60 and SM70 and each permit is under review by the Bureau of Ocean Energy Management ("BOEM") Gulf of Mexico Region office in New Orleans, Louisiana. Byron has no reason to believe these permits will not be approved in the normal course of the approval process.

To drill any well offshore, an operator must also file an Application for Permit to Drill ("APD") with the Bureau of Safety and Environmental Enforcement ("BSEE"). Byron has filed APD's for the next phase of drilling at SM69 and SM58. The APD for the SM69 E2 well is fully approved and the APD's for the proposed SM58 G3 and G4 wells have also been filed and are under review. Byron does not anticipate any delays in the approval process and expects approval in the normal course of business.

2. Eugene Island blocks 62, 63, 76 and 77

Byron acquired Eugene Island blocks 62, 63, 76 and 77 ("EI62/63/76/77"), at Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana. Water depth in the area is approximately 20 feet.

Byron currently holds a 100% WI and an 87.5% NRI in EI62/63/76/77.

EI62/63/76/77 were designated as the Eugene Island 77 Field in the 1960's and have produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the Eugene Island 77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

On the basis of proprietary RTM, undertaken by WesternGeco (a Schlumberger group company) in 2014 of 3D seismic data over the entire four block Eugene Island 77 Field, Byron acquired EI62/63/76/77 at the OCS Lease Sale 250. As a result of this detailed work Byron significantly upgraded the reserve potential of EI62/63/76/77.

In the September 2018 quarter, Byron began a reprocessing effort similar that undertaken on the SM71 Project Area with WesternGeco over all four Eugene Island blocks leased by the Company. Analysis of the reprocessed data is continuing while preliminary well planning has also started.

BYRONENERGY LIMITED

Project Updates (cont)

3. Main Pass 293, 305 & 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 & 306 ("MP 306 Field") acquired at the Gulf of Mexico, OCS Lease Sale 251 held in New Orleans, Louisiana on 15 August 2018.

The three leases comprise the MP306 field as formerly designated by the BOEM. The MP 306 Field was discovered in 1969 and lies in approximately 200 feet of water. Total produced hydrocarbons from the field are 96 million barrels of oil and 107 bcf of gas from 172 of the 249 total wells drilled. The field ceased production in late 2009 and the last well drilled on any of these blocks was in 2004. The production was from a number of sands ranging from a depth of 4,000 to 9,000 feet.

The structural complexity of the salt dome combined with the stratigraphic variation of the trapping sands and possible deeper stratigraphic targets makes this salt dome an ideal candidate for RTM seismic imaging, similar to Byron's operated SM71 salt dome project.

The Company has started scoping an RTM seismic imaging project over the MP306 field.

Properties

As at 31 March 2021, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, and coastal marshlands of Louisiana, 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 57	Byron	100.00/81.25	June 2022	21.98
South Marsh Island Block 59	Byron	100.00/81.25	June 2022	20.23
South Marsh Island Block 60	Byron	100.00/87.50	June 2024	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 Ankor	100.00/83.33** 53.00/44.167	Production	20.23
South Marsh Island Block 69 (NE ¼ of NE ¼)	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
Eugene Island Block 62	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 63	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 76	Byron	100.00/87.50	June 2023	20.23
Eugene Island Block 77	Byron	100.00/87.50	June 2023	20.23
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
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
Tcf = trillion cubic feet

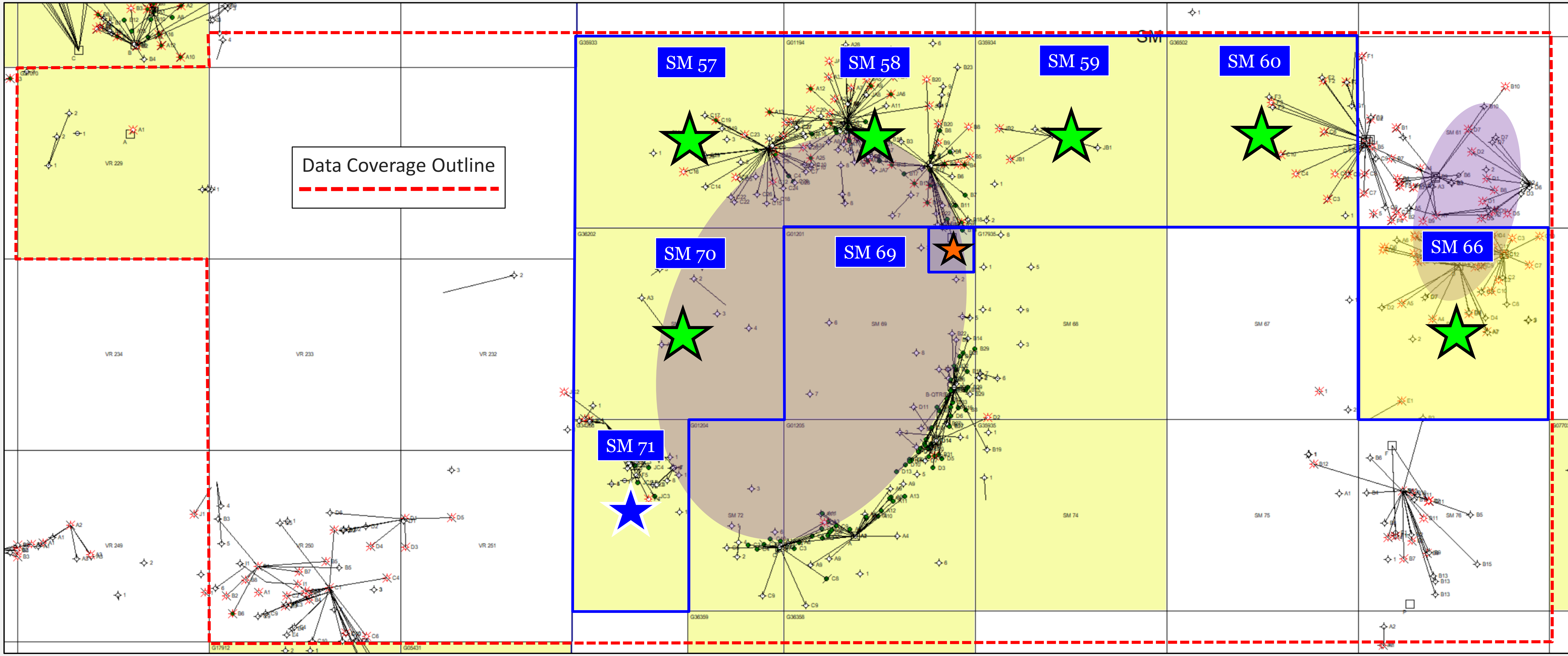
Conversions

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 1.09 btu's currently for SM71 / SM58 production; the heat content of SM71 / SM58 gas may vary over time.

ATTACHMENT 1

Byron Energy GOM South Marsh Island Leases and RTM Data Coverage Area March 2021



BYRONENERGY INC.	BYRONENERGY INC. OTTO ENERGY	BYRONENERGY INC. ANKOR ENERGY
Byron 100% WI	Byron/Otto 50% WI	Ankor/Byron Agreement

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 March 2021

Consolidated statement of cash flows			**Current quarter US$'000**	**Year to date (9 months) US$'000**
1.	**Cash flows from operating activities**			
1.1	Receipts from customers		10,634	22,616
1.2	Payments for			
	(a)	exploration & evaluation (surplus drill pipe proceeds)	86	20
	(b)	development	(7,270)	(32,971)
	(c)	production	(1,675)	(3,939)
	(d)	staff costs	(712)	(1,922)
	(e)	administration and corporate costs	(548)	(1,346)
1.3	Dividends received (see note 3)		-	-
1.4	Interest received		-	1
1.5	Interest and other costs of finance paid		(759)	(2,295)
1.6	Income taxes paid		-	-
1.7	Government grants and tax incentives		-	-
1.8	Other (provide details if material)		-	-
	- Cash Contributions from JV partners (surplus drill pipe refund)		(19)	173
	- Oil revenue prepayment		3,500	3,500
1.9	**Net cash from / (used in) operating activities**		**3,237**	**(16,163)**

2.	**Cash flows from investing activities**			
2.1	Payments to acquire or for:			
	(a)	entities		
	(b)	tenements	-	(178)
	(c)	property, plant and equipment		
	(d)	exploration & evaluation	(207)	(549)

Consolidated statement of cash flows		**Current quarter US$'000**	**Year to date (9 months) US$'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**	**(207)**	**(727)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	-	1,533
3.2	Proceeds from issue of convertible debt securities		
3.3	Proceeds from exercise of options		
3.4	Transaction costs related to issues of equity securities or convertible debt securities	-	(36)
3.5	Proceeds from borrowings	-	3,500
3.6	Repayment of borrowings	(1,401)	(1,753)
3.7	Transaction costs related to loans and borrowings		
3.8	Dividends paid		
3.9	Other (provide details if material)	-	(4)
3.10	**Net cash from / (used in) financing activities**	**(1,401)**	**3,240**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	1,498	16,645
4.2	Net cash from / (used in) operating activities (item 1.9 above)	3,237	(16,163)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(207)	(727)

	Consolidated statement of cash flows	**Current quarter US$'000**	**Year to date (9 months) US$'000**
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(1,401)	3,240
4.5	Effect of movement in exchange rates on cash held	-	132
4.6	**Cash and cash equivalents at end of period**	**3,127**	**3,127**

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	3,127	1,498
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)**	**3,127**	**1,498**

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	458
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$ 72, (ii) Executive directors' salaries and service fees of US$ 207k and A$ 151k, and (iii) quarterly interest payments of US$ 47k and A$ 43k 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 $'000**
7.1a	Loan facilities (unsecured and repayable by 31 March 2022, bearing 10% interest p.a.)	US$ 2,000 & A$ 2,100	US$ 2,000 & A$ 2,100
7.1b	Loan facilities (secured over the SM71 & SM58 assets on a 3 year fixed term, bearing 15% interest p.a with no loan repayments until December 2020.)	US$ 16,750	US$ 16,750
7.2	Credit standby arrangements	-	-
7.3	Other (please specify)	-	-
7.4	**Total financing facilities**	US$ 18,750 & A$ 2,100	US$ 18,750 & A$ 2,100
7.5	**Unused financing facilities available at quarter end**		Nil
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.		

8.	***Estimated cash available for future operating activities***	**US$'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	3,237
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(207)
8.3	**Total relevant outgoings (item 8.1 + item 8.2)**	**3,030**
8.4	Cash and cash equivalents at quarter end (item 4.6)	3,127
8.5	Unused finance facilities available at quarter end (item 7.5)	-
8.6	**Total available funding (item 8.4 + item 8.5)**	**3,127**
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**1.0**

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:
Receipts from customers will depend on production levels and oil and gas prices. Payments for development expenditure will be substantially less in the next quarter than the previous three quarters.

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: The Company has taken the following steps to raise further cash to fund its operations: (i) appointed Seaport Global to assist in pursuing debt financing in the USA, as announced to the ASX on 27 January 2021, and (ii) received a prepayment of US$3.5 million in February 2021 from the hedging counterparty under the oil forward sale agreement. The amount of US$3.5 million will be repaid from oil revenues under the forward sale agreement over four months commencing in May 2021.	
8.8.3	Does the entity expected to be able to continue its operations and to meet its business objectives and, if so, on what basis?
Answer: Yes, the entity is expect to be able to continue its operations and to meet its business objectives for the reasons outlined in 1 and 2 above.	

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: 26 April 2021..

Authorised by: .The 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.