Annual Report 2023

BYRONENERGY

Contents

Highlights

Byron Energy is an independent oil and natural gas exploration company, headquartered in Australia, with operations in the shallow water offshore Louisiana in the Gulf of Mexico.

SM71, SM58 and **SM69 E2** Oil and Gas Fields

SM71 and SM58 Field Discoveries and SM69 E2 Well Discovery made possible through use of RTM seismic technology

Key

- SM71, SM58 and SM69 E2
- Exploration Blocks

SM58 production (incl E2 well)	SM71 Production	Reserves (Net)
1,160 Bopd	**1,540** Bopd	**2P 13.8** MMbo
Production (gross)	**Production (gross)**	**Reserves**
Approximately 1,160 bopd and 4.2 MMcfd average for 2023	Approximately 1,540 bopd and 1.3 MMcfd average for 2023	2P (net) 13.8 MMbo 2P (net) 31.1 Bcf 2P (net) 18.9 MMboe

Chairman's Letter

Byron intends to continue its strategy of adding to the Company's proved developed reserves by drilling low risk development wells, targeting multiple oil sands in the SM58 field.

Dear Shareholder,

The year ending 30 June 2023 saw the strong oil and gas prices, experienced during 2021 and the first half of calendar 2022, come to an end. Nevertheless, oil prices remained at reasonably attractive levels during the year enabling Byron to generate strong cashflows. After 30 June 2023, the oil price has staged a rally to once again provide a positive impetus to our operations in the Gulf of Mexico, USA.

West Texas Intermediate (WTI), the US marker oil price, decreased from approximately US$108 per barrel on 30 June 2022 to approximately US$71 on 30 June 2023, a decrease of 34%. The Henry Hub natural gas mmbtu spot price fell from approximately US$5.40 on 30 June 2022 to US$2.80 on 30 June 2023, a decrease of 48%.

The oil price decrease during the 2023 financial year was largely driven by rising interest rates in key economies and a slower than expected post-Covid recovery in Chinese manufacturing and consumption. More recently, increasing demand and the extension by OPEC+ of its supply cuts to 31 December 2023, have boosted oil prices.

U.S. natural gas prices closed the June 2023 financial year at US$2.80 per mmbtu but have fallen back mostly below US$2.80 since 30 June 2023. Rising USA output and mostly mild weather kept demand low and allowed utilities to leave more gas in storage than usual.

During the 2023 financial year Byron produced and sold approximately 0.575 million barrels of oil (mmbo) (2022 0.517 mmbo) and over 1.4 billion cubic feet of gas (bcfg) (2022 2.0 bcfg), generating net revenue of approximately US$53.0 million for the 2023 year (2022 US$53.1 million). Approximately 84% of Byron's net revenue comes from oil production and sales.

Importantly, we continued to operate the Company's production facilities and wells with an excellent safety and environmental record.

Notwithstanding our solid production (mainly oil) and revenue levels, the Byron share price continues to languish, like many other oil and gas companies of a similar size, and declined during the 2023 financial year, from $A0.17 per share to $A0.07 per share. While the share price has improved after 30 June 2023, in line with increased oil prices and successful drilling of SM58 G6 and G4 wells, in my view the share price continues to trade well below the intrinsic value of the Company's assets. However, many small to medium oil and gas companies continue to remain out of favour with the investors and the general public.

During August and September 2023 Byron drilled the SM58 G6 and the SM58 G4 wells. The G6 well drilled the Gila Trout prospect and the G4 well drilled the Tiger Trout prospect. These wells were planned to be drilled during the 2023 financial year but were delayed until August 2023 due to rig unavailability.

In the G6 well, one of the two primary objective sands, the L2 Sand, logged 32 feet of Measured Depth (MD) net oil and gas pay (23 feet of true vertical Thickness (TVT)). In addition, 12 feet MD oil pay was logged in the I Sand (10 feet TVT). The second primary objective sand, the N2, was found to be of poor reservoir quality in the G6 well but was encountered with 77 feet MD of net hydrocarbon pay (78 feet TVT) in the G6BP1 well, a sidetrack from the G6 well about 300 feet laterally from the G6 original hole

In the G4 well 82 feet of net oil pay (MD) (59 feet TVT) was logged in the primary objective K4 sand. The secondary G4 targets (K6 and L2) were both encountered hydrocarbon charged but poorly developed and unsuitable for production.

Both G6 and G4 wells will be completed for production during the December 2023 quarter and should add substantially to production output from the SM58 G platform. In addition, the N2 sand in the G5 well will be completed for production utilising a coiled tubing unit.

As of 30 June 2023, the SM58 G facility has produced approximately 8.3 bcfg and 0.7 mmbo (gross) on a cumulative basis from five wells (G1, G2, G3, G5 and E2).

From March of 2018 until end of June 2023, a total of 4.6 mmbo and 5.5 bcfg has been produced from the SM71 facility, making Byron operated SM71 one of the highest ranked producing blocks on the Gulf of Mexico Shelf in that period. Over the last year production from SM71 has declined as predicted, in line with increasing water production from the F3 well starting in July 2022.

On 28 August 2023, Byron released its 30 June 2023 reserves and resources statement. As at 30 June 2023 the Remaining 1P Reserves, net to Byron, are 8.5 mmbo and 23.2 bcfg with Remaining 2P Reserves, net to Byron, of 13.8 mmbo and 31.0 bcfg. In 2023 we achieved a 94% production replacement in our 1P reserves.

Byron has funded its SM58 G6 and G4 development activity with internally generated cash flows and by once again leveraging its relationship with the buyer of its oil, a global supermajor, willing to prepay for some of Byron's future oil production. This has allowed the Company to avoid new equity raisings and conventional debt funding which usually carries highly restrictive debt covenants and more extensive hedging requirements.

Byron intends to continue its strategy of adding to the Company's proved developed reserves by drilling low risk development wells, targeting multiple oil sands in the SM58 field where we have mapped extensive undeveloped reserves and prospective resources on a number of prospects. In March 2023 Byron successfully bid on and was awarded three new GOM leases (SM57, Grand Isle 63 and 72) and will continue to evaluate and acquire additional highly prospective leases in the shallow waters of the GOM.

Once again, I thank our management team, employees and contractors who have worked very hard in challenging industry and global circumstances. I also acknowledge the contribution of our non-executive directors and thank them for continued support and guidance.

Finally, on behalf of the Board, I would like to thank our shareholders for their ongoing support.

Doug Battersby
Chairman

Review of Operations

Production for the year ended 30 June 2023 was approximately 575,000 bbls of oil and over 1.4 bcf of gas, net to Byron, generating net sales revenue of approximately US$53 million and EBITDAX of US$39.3 million.

Introduction

During the year ended 30 June 2023, Byron focused primarily on maximising production of oil and gas from the Byron operated producing field. Development drilling at SM58 originally planned for the year ended 30 June 2023 was delayed until August 2023 due to rig unavailability.

Highlights for the year ended 30 June 2023 included:

- Net Proved Reserves (1P) of 8.5 MMbl and 23.2 Bcfg, (12.4MMboe), a decrease of approximately 6% compared to 2022 mainly due to production;
- Net Proved and Probable Reserves (2P) of 13.8 MMbl and 31.1 Bcfg (18.9 MMboe), an increase of approximately 2% over 2022;
- Net sale revenue of US$53.0 million for 2023 compared to US$53.1 million in 2022;
- Earnings before interest, tax, amortisation, share based payments, impairment, realised oil hedge price losses and depreciation and exploration expense ("EBITDAX") for the year ended 30 June 2023 totalled US$39.3 million, a decrease of 5% compared to US$41.6 million for the year ended 30 June 2022, primarily as a result of higher lease operating costs, lower realised oil and gas prices, decreased gas production, partially offset by higher oil production.
- Lease Operating Expenses, excluding amortisation, of less than US$11.00/boe in 2023, remain well below Gulf of Mexico peer producer averages.

Net Proved Reserves (1P) of

8.5MMbl **23.2**Bcfg, (12.4MMboe),

a decrease of approximately 6% compared to 2022 mainly due to production

Net Proved and Probable Reserves (2P) of

13.8MMbl **31.1** Bcfg, (18.9MMboe),

an increase of approximately 2% over 2022

Review of Operations continued

Production for the year ended 30 June 2023 was approximately 575,000 bbls of oil and over 1.4 bcf of gas, net to Byron, generating net sales revenue of approximately US$53 million.

Key statistics	Year ended 30 June 2023	Year ended 30 June 2022
Production (sales)(net to Byron)		
Oil (bbls)	**575,645**	516,734
Gas (mmbtu)	**1,607,642**	2,299,907
Net revenue after royalties and oil transportation charges (US$ million)	**53.0**	53.1
Realised oil price after transport charges (US$/bbl)	**77.22**	78.81
Realised gas price after transport charges (US$/mmbtu)	**4.97**	5.05
EBITDAX (US$ million)	**39.34**	41.58

Byron's Proved Reserves (1P) were 8.5 Mmbbl of oil and 23.2 Bcf of gas as at 30 June 2023 and Proved and Probable Reserves (2P) were 13.8 Mmbbl of oil and 31.0 Bcf of gas.

Net remaining reserves as at 30/6/2023	Oil (MMbo)	Gas (Bcf)	MMboe (6:1)
Proved	**8.5**	**23.2**	**12.4**
Probable	5.3	7.9	6.5
Proved and Probable (2P)	**13.8**	**31.1**	**18.9**
Possible	4.8	5.3	5.8
Proved, Probable and Possible (3P)	**18.6**	**36.4**	**24.7**
Prospective Resources	**18.4**	**208.2**	**53.0**

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.

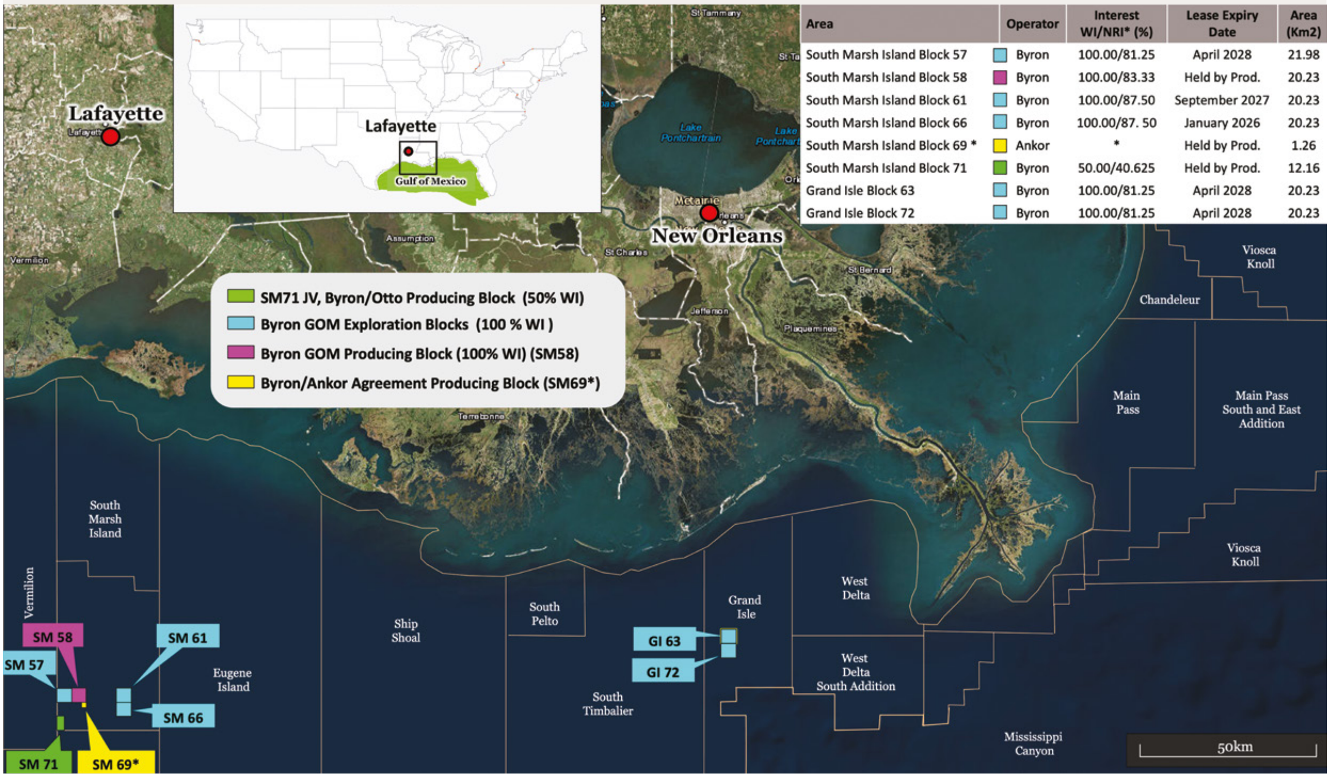
Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

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.

Oil and Gas Properties

Byron is focused on the shallow waters of the Outer Continental Shelf (OCS) in the Gulf of Mexico (GOM), with a portfolio of leases, as shown below.

Byron Energy Gulf of Mexico Lease Map as at October 2023



Area	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km2)
South Marsh Island Block 57	Byron	100.00/81.25	April 2028	21.98
South Marsh Island Block 58	Byron	100.00/83.33	Held by Prod.	20.23
South Marsh Island Block 61	Byron	100.00/87.50	September 2027	20.23
South Marsh Island Block 66	Byron	100.00/87. 50	January 2026	20.23
South Marsh Island Block 69 *	Ankor	*	Held by Prod.	1.26
South Marsh Island Block 71	Byron	50.00/40.625	Held by Prod.	12.16
Grand Isle Block 63	Byron	100.00/81.25	April 2028	20.23
Grand Isle Block 72	Byron	100.00/81.25	April 2028	20.23

* Refer to ASX release 1 April, 2019 for details; Ankor was subsequently aquired by W&T Offshore.

Review of Operations continued

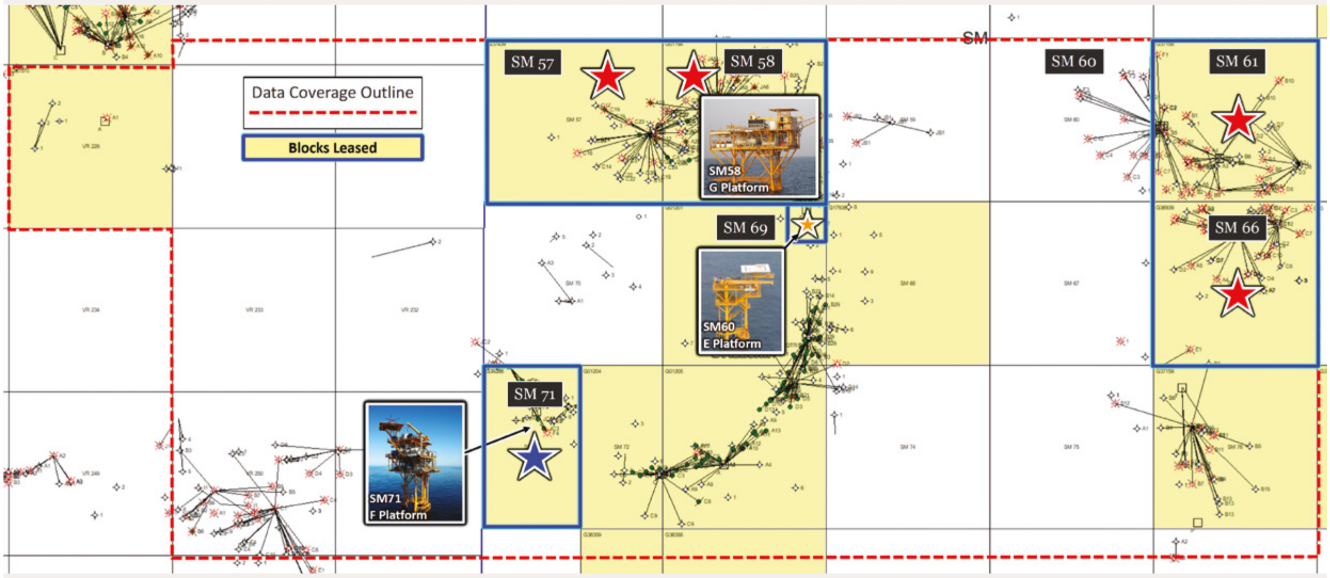
1. South Marsh Island 73 Salt Dome

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 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 ("TVD"). The majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

Byron is the operator and 100% working interest holder in 4 areas of interest around the SM73 field, comprising SM 57/58/61/66. Byron is also the operator of SM71, where it has a 50% working interest In addition, Byron holds a non-operated interest in the SM58 E1 well and SM69 E platform in the NE ¼ of NE ¼ of SM69), as shown in the map below.

In 2018/19 Byron undertook high effort seismic reprocessing of approximately 172 square miles (445 square kilometres) of high quality modern seismic data the Company previously licensed from WesternGeco, a Schlumberger group company.

Byron Energy GOM South March Island Lease and RTM Data Coverage Area



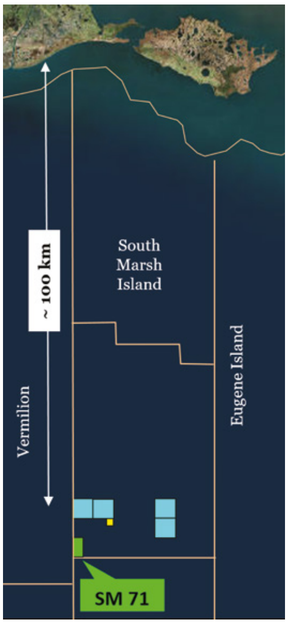
* Refer ASX release 1 April, 2019; Ankor was subsequently aquired by W&T Offshore.

(a) South Marsh Island 71 (WI 50%; NRI 40.625%; Operator, Byron)

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. The F1 and F3 wells are producing in the primary D5 Sand reservoir, the F2 and F4 wells are producing from the Upper J1 Sand. As of 30 June 2023, the SM71 F facility has produced approximately 4.6 million barrels of oil (Mmbo) (gross) since initial production began. The facility has also produced approximately 5.5 billion cubic feet of gas (Bcfg) (gross).

South Marsh Island 71 (SM71) Project Summary

Working Interest Holders	**Byron Energy 50% / Otto Energy 50%**
Operator	Byron Energy Inc.
Water Depth	40 meters (131')
Previous SM71 Production	3.9 mmbo + 10 bcf (1995 to 2010)
Acquired	OCS Sale 222 June 2012 for US$166,620
Byron Interest	50% WI, 40.625% NRI
Byron #1 (F1) discovery well	April 2016, 132' TVT NFO
F Platform Installation Completed	October 2017
Byron F2 & F3	F2 November 2017, 205 TVT NFO F3 January 2018 , 175 TVT NFO
Initial Production	F1 first prod. March 2018 F2 & F3 first prod. April 2018
Total Gross Project Oil & Gas Produced from March 2018 to June 2023	4.6 mmbo + 5.5 bcf
Net 2P Remaining Reserves*	2.7 mmbo + 2.2 bcf



SM71 Reserve Summary*	**Gross Reserves / Remaining 30/6/23**		**Net Reserves / Remaining 30/6/23**	
	mbo	**mmcf**	**mbo**	**mmcf**
1P Proved	**3,980**	**2,813**	**1,627**	**1,149**
Probable	2,646	2,679	1,075	1,088
2P	**6,626**	**5,492**	**2,702**	**2,237**
Possible	2,602	2,107	1,057	856
3P	**9,228**	**7,599**	**3,759**	**3,093**
	Gross Prospective Resource		**Net Prospective Resource**	
Prospective	**2,406**	**48,948**	**977**	**19,885**

* Collarini and Associates reserves report as at 30th June2023; refer ASX release 28 August 2023.

SM71 Project Status

Byron's share of SM 71 production for the year ended 30 June 2023, compared to 2022 year, is shown in the table below.

Production (sales)(net to Byron)	Year ended 30 June 2023	Year ended 30 June 2022
Gross production		
Oil (bbls)	**563,838**	783,716
Gas (mmbtu)	**498,832**	660,806
Byron share of Gross Production (WI basis)		
Oil (bbls)	**287,293**	392,742
Gas (mmbtu)	**263,865**	334,639
Net production (Byron share (NRI basis)		
Oil (bbls)	**233,426**	319,103
Gas (mmbtu)	**214,390**	217,894

Oil production for the year ended 30 June 2023 was below the volumes achieved for the 2022 year mainly due to lower production from SM71 F3 well where the water cut increased during the year (average water cut of approximately 39% in 2023 compared to nil% for 2022). Gas production for the 2023 year was lower than for the 2022 year mainly due to the F3 well decline.

Byron's share of net revenue, after royalties, oil transportation charges and other customary price adjustment, for the 2023 year from SM71 of approximately US$18.1 million was approximately 26% below US$24.4 million for the 2022 year, due to lower sales volumes and lower realised gas prices, offset by slightly higher oil prices. Lease operating expenses, excluding amortisation and depreciation, for the 2023 year were US$2.9 million (2022 US$2.4 million).

As of 30 June 2023, Collarini assigned proved reserves (net to Byron) of 1.1 Mmbbl and 1.2 Bcf and 2P reserves (net to Byron) of 3.0 Mmbbl and 2.2 Bcf to SM71.

(b) South Marsh Island 58 (WI 100%; NRI 83.333%; Operator, Byron)

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 earned a 100% WI in the SM69 E2 well (E2) under the Joint Exploration Agreement (JEA) with ANKOR group (now WT Offshore Inc) which provided for the drilling of the E2 exploration well operated by Byron. By funding 100% of the E2 well, Byron earned a 100% WI and 80.33% NRI until E2 Project Payout. Effective 1st January 2023, Byron's 100% WI and 80.33% NRI in the SM69 E2 well was 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% WI, 25% NRI in the E2 well.

Water depth in the area is approximately 132 feet.

As of 30 June 2022, the SM58 G facility has produced approximately 8.3 Bcfg and 0.7 million barrels of oil and condensate (gross) on a cumulative basis from five wells (G1, G2, G3 G5 and E2).

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 300 bopd and no formation water. Gas production from the G1 well has continued to follow a natural and predictable pressure decline.

The SM58 G2 produces from the O Sand producing oil, gas 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 and 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 well, 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.

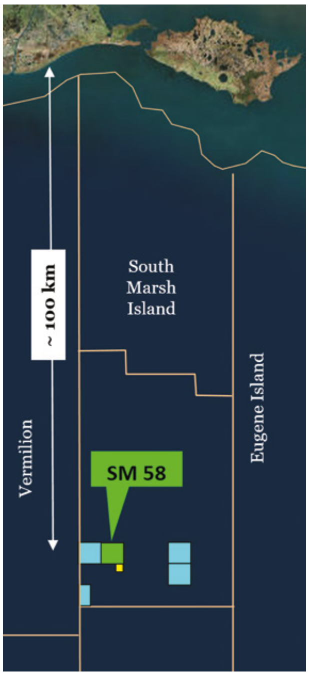
Subsequent to 30 June 2023 Byron drilled the SM58 G6 and the SM58 G4 wells. These wells were planned to be drilled during the 2023 financial year but were delayed until August 2023 due to rig unavailability.

In the G6 well, the Gila Trout prospect, one of the two primary objective sands, the L2 Sand, logged 32 feet of Measured Depth (MD) net oil and gas pay (23 feet of true vertical Thickness (TVT)). In addition, 12 feet MD oil pay was logged in the Io Sand (10 feet TVT). The second primary objective sand, the N2, was found to be of poor reservoir quality in the G6 well but was encountered with 77 feet MD of net hydrocarbon pay (78 feet TVT) in the G6BP1 well, a sidetrack from the G6 well about 300 feet laterally from the G6 original hole. In the G4 well, the Tiger Trout prospect, 82 feet of net oil pay (MD) (59 feet TVT) was logged in the primary objective K4 sand. The secondary G4 targets (K6 and L2) were both encountered hydrocarbon charged but poorly developed and unsuitable for production.

Both G6 and G4 wells will be completed for production during the December 2023 quarter and should add substantially to production output from the SM58 G platform. In addition, the N2 sand in the G5 well is planned to be completed for production utilising a coiled tubing unit.

South Marsh Island 58 Project Summary

Working Interest Holders	Byron Energy Inc.
Operator	Byron Energy Inc.
Water Depth	~37 meters (121')
Previous SM58 Production	35.8 mmbo + 265 bcf
Acquired Jan 1st 2019 from Fieldwood Energy	US$4,250,000
Byron Interest	100% WI, 83.33% NRI*
Byron #1 (G1) discovery well	September 2019, 301' TVT Hydrocarbon Pay
G Platform Installation Completed & Installed	July 2020
Initial production SM58 G1 and G2ST followed by E2, G3 and G5	G1 first production September 2020 G2 first production November 2020 E2 first production October 2021* G3 first production August 2022 G5 first production July 2022
Total Gross Project Oil & Gas Produced from Sept. 2020 to June 2023 (incl SM69E 2 well)	8.3 BCf and 723,000 bbls
G Platform Capacity	8,000 bopd + 80 mmcfgpd +8,000 bwpd
Net 2P Remaining Reserves SM58 (excl E1, E2 & future E3 well)	9.2 mmbo + 27.6 bcf**



SM58 Reserve Summary#	Gross Reserves / Remaining 30/6/23		Net Reserves / Remaining 30/6/23*	
	mbo	mmcf	mbo	mmcf
1P Proved	**6,973**	**25,089**	**5,801**	**20,808**
Probable	4,957	8,155	4,131	6,796
2P	**11,930**	**33,244**	**9,932**	**27,604**
Possible	4,507	5,410	3,756	4,508
3P	**16,437**	**38,654**	**13,687**	**32,112**
	Gross Prospective Resource		**Net Prospective Resource**	
Prospective	**14,656**	**48,806**	**12,196**	**40,403**

* Byron's 100% WI and 80.33% NRI in the SM69 E2 well reduced effective 1 January 2023 to 70% WI with an unburdened 58.33% NRI after WT Offshore exercised its option to convert its overriding royalty interest into a working interest in the E2 well. 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. Excludes SM58 SM69 E2&E3 net 2P remaining reserves of 1.1 mmbl and 1.2 bcf.

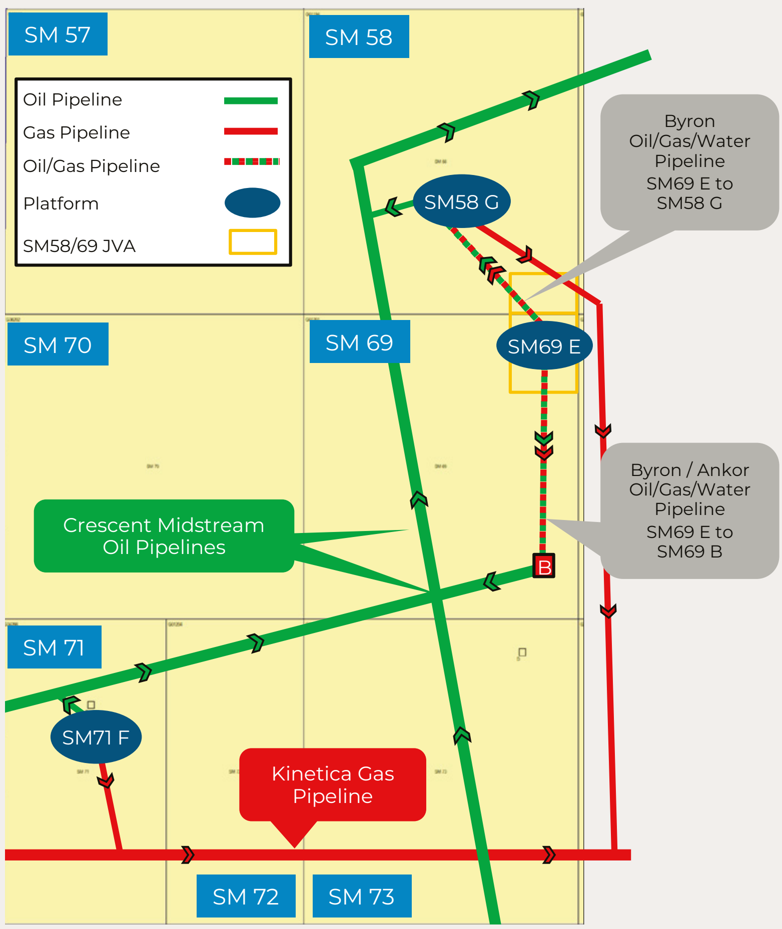
\# Collarini and Associates reserves report as at 30th June 2023; refer ASX releases 28 August 2023.

SM58 Project Status

Byron's share of SM 58 production for the year ended 30 June 2023, compared to 2022 year, is shown in the table below.

Production (sales)(net to Byron)	Year ended 30 June 2023	Year ended 30 June 2022
Gross production		
Oil (bbls)	**429,782**	220,078
Gas (mmbtu)	**1,701,239**	2,432,082
Byron share of Gross Production (WI basis)		
Oil (bbls)	**393,612**	220,078
Gas (mmbtu)	**1,671,879**	2,432,082
Net production (Byron share (NRI basis)		
Oil (bbls)	**324,114**	178,183
Gas (mmbtu)	**1,390,034**	2,024,505

Byron pipelines schematic



Oil production for the year ended 30 June 2023 was above the volumes achieved for the 2022 year mainly due to higher daily rates achieved by the G1 well.

For the year ended 30 June 2023, Byron's share of net revenue from SM58 after royalties, and oil transportation charges and other customary price adjustments was US$33.5 million compared to US$27.1 million for the 2022 year, due to higher oil production partly offset by lower gas sales volumes and lower realised oil and gas prices. Lease operating expenses (excluding depreciation and amortisation) were US$5.4 million for the 2023 year (2022 US$4.2 million).

As of 30 June 2023, Collarini has assigned proved reserves (net to Byron) of 5.8 Mmbbl and 20.8 Bcf and 2P reserves (net to Byron) of 9.9 Mmbbl and 27.6 Bcf to SM58 as at 30 June 2023.

(c) SM 58E1/69E Platform

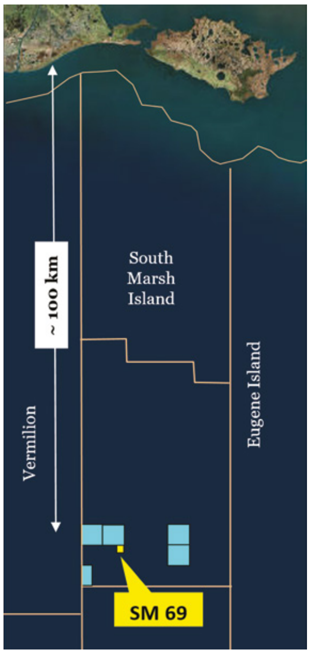
Byron owns a 53% WI and a 44.17% NRI in the joint area reservoirs from the surface to a depth of 7,490 feet TVD, located in the S1/2 of the SE1/4 of the SE1/4 of SM58, as well as a 53% working interest in the SM 69 E platform. W&T Offshore Inc (as successor to Ankor Energy, LLC) is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM 58 E1 well and E platform which is located in the NE corner of the SM 69 block.

The SM58 E1 well produces from the K Sand recompleted during the March 2021 quarter.

While the SM 69 E2 well (referred to above) is located on the SM 69 E platform, Byron produces the SM69 E2 well back to the SM58 G platform through a flowline laid in July 2020. Hydrocarbons from the E2 well are processed and sold through the SM58 G Platform.

South Marsh Island 69 (SM58 E1 & SM69) Project Summary

Working Interest Holders	Byron Energy Inc.
Operator SM69E2 well Operator SM58 E1/SM69 E Platform	Byron Energy Inc. W&T Offshore
Water Depth	38 meters (125')
Previous SM58 Production	35.8 mmbo + 265 bcf
Acquired SM58 E1/SM69 E Platform Jan 1st 2019 from Fieldwood Energy Farmed into SM69E2 via JEA with ANKOR	US$4.85 million 100% WI/80.33% NRI for funding 100% of SM69 E2 well[#]
Byron SM69E2 discovery well	September 2021, 81' TVT Hydrocarbon Pay
SM58 G Platform Installation Completed & Installed in July 2020	July 2020 (SM69 E2 well produced back to SM58 G platform through pipeline laid in July 2020)
Initial production SM69 E2 (produced through SM58 G platform)	Commenced on 21 October 2021
Net 2P Remaining Reserves (includes existing E1 and E2 wells and future E3 well)*	1.1 mmbo + 1.2 bcf



SM58E1/SM69E2 Reserve Summary*	Gross Reserves / Remaining 30/6/23		Net Reserves / Remaining 30/6/23	
	mbo	mmcf	mbo	mmcf
1P Proved	**2,214**	**2,533**	**1,116**	**1,197**
Probable	59	21	26	9
2P	**2,273**	**2,554**	**1,142**	**1,206**
Possible	-	-	-	-
3P	**2,273**	**2,554**	**1,142**	**1,206**
	Gross Prospective Resource		**Net Prospective Resource**	
Prospective	**856**	**857**	**545**	**545**

\# Effective 1/1/23 Byron's WI and NRI were reduced to 70% WI and 58.33% NRI with the E2 well having achieved payout in December 2022.

* Collarini and Associates reserves report as at 30th June 2023; refer ASX releases 28 August 2023.

Review of Operations continued

Byron's share of production (excluding E2 well) for the year ended 30 June 2023 is shown in the table below.

Production (sales)(net to Byron)	Year ended 30 June 2023	Year ended 30 June 2022
Gross production		
Oil (bbls)	**40,994**	44,033
Gas (mmbtu)	**7,287**	7,934
Byron share of Gross Production (WI basis)		
Oil (bbls)	**21,727**	23,337
Gas (mmbtu)	**3,862**	4,210
Net production (Byron share (NRI basis)		
Oil (bbls)	**18,106**	19,448
Gas (mmbtu)	**3,218**	3,508

Oil and gas production for the year ended 30 June 2023 was slightly below the volumes achieved for the 2022 year.

For the year ended 30 June 2023, Byron's share of net revenue from SM58 E1 well was approximately US$1.5 million compared to US$1.6 million for the 2022 year, mainly due to lower realised oil and gas prices.

Collarini has assigned 2P reserves (net to Byron) of 1.1 Mmbbl and 1.2 Bcf to the developed and undeveloped reserves in S ½ of SE ¼ of SE ¼ of SM58) and the NE ¼ of NE ¼ of SM69), as at 30 June 2023.

Portfolio Optimisation

Byron actively managed its portfolio of exploration and evaluation assets during the year ended 30 June 2023 with the aim of maintaining Byron's prospect inventory and footprint in the blocks encompassing the SM 73 salt dome, in the shallow waters of the GOM, while extending the average lease maturity date.

During year ended 30 June, 2023 Byron was awarded:

(a) South Marsh Island 61, after being the high bidder on the block at GOM, OCS Lease Sale 257 held in New Orleans, Louisiana on 17 November 2021, and

(b) Grand Isle 63 & 72 and South Marsh Island 57 after being the high bidder on the blocks at GOM, OCS Lease Sale 259 held in New Orleans, Louisiana on 29 March 2023.

During year ended 30 June, 2023 Byron relinquished the following leases:

(a) South Marsh Island 60 lease during June 2023 quarter, with only a year to expiry;

(b) South Marsh Island 70 lease, having completed a focussed post-stack seismic reprocessing effort over its leasehold in the SM58 project area and as a result of this work, and having regard to significantly lower gas prices, Byron decided not to drill the SM70 Golden Trout prospect and instead, relinquish the SM70 lease; and

(c) Main Pass 297/305/306, after a full evaluation Byron determined that several previously identified potential drilling opportunities did not meet the Company's technical and economic risk criteria.

South Marsh Island Area Exploration and Evaluation Assets

South Marsh Island 57/61/66

Byron holds a 100% WI and an 81.25% NRI in South Marsh Island 57 (SM 57). SM 57 is adjacent to the Company's SM58 G platform where Byron operates a total of five active wells. SM57 was relinquished by the Company in 2021, but a more recent proprietary seismic reprocessing effort has improved the prospectivity of the previously mapped oil and gas prospects.

Byron holds a 100% WI and an 87.50% NRI in South Marsh Island 61 (SM 61) and South Marsh Island 66 (SM 66).

SM 61 and SM66 are in close proximity to Byron's SM58 platform and increases Byron's footprint in the South Marsh Island 73 Field. Water depth in the area is approximately 125 feet.

SM57, SM61 and SM66 blocks were part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites

These blocks will be assessed against existing project opportunities and moved into the Company's drilling schedule based on their relative risk reward ranking.

Grand Isle Area Exploration and Evaluation Assets

Grand Isle 63/72

Byron holds a 100% WI and an 81.25% NRI in Grand Isle 63/72 (GI 63/72).

The GI 63/72 blocks represent an additional salt dome project area for the Company and were evaluated using RTM 3D seismic data.

Each block has had minor oil and gas production in the past and the RTM data indicates the possibility of remaining exploration and development potential on these blocks.

The two blocks lie in water depths of about 120 feet with good proximity to active oil and gas sales pipelines. These two blocks are approximately 125 miles east of Byron's current SM58/71 operating areas giving Byron good geographical diversity, in the event of hurricanes, should the Company discover and develop commercial hydrocarbons on these leases.

Review of Operations continued

Properties

As at 30 June 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	Lease Area (Km²)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	**12.16**
Block 57	Byron	100.00/81.25	April 2028	**21.98**
Block 61	Byron	100.00/87.50	September 2027	**20.23**
Block 58 (excluding E1 well)	Byron	100.00/83.33**	Production	**20.23**
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)	53.00/44.16667		
SM69 (NE ¼ of NE ¼) (E-2 well)	Byron	70.00/58.33***	Production	**1.3**
Block 66	Byron	100.00/87.50	December 2025	**20.23**
Grand Isle				
Block 63	Byron	100.00/81.25	April 2028	**20.23**
Block 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.

Reserves and Resources

The Company's reserves and resources estimate as at 30 June 2023 was released to the ASX on 28 August 2023 and is summarised in the points beside.

- Proved Reserves (1P): 8.5 Mmbbl of oil and 23.2 Bcf of gas
- Proved and Probable Reserves (2P): 13.8 Mmbbl of oil and 31.0 Bcf of gas
- Proved, Probable and Possible Reserves (3P): 18.6 Mmbbl of oil and 36.4 Bcf of gas
- Prospective Resources: 18.4 Mmbbl of oil and 208.2 Bcf of gas

The combined remaining reserves and prospective resources, net to Byron, of 30 June 2023 are as follows:

Byron Energy Limited – Reserves & Resources Gulf of Mexico, Offshore Louisiana, USA

Net Remaining as of 30 June	Category	Oil (Mbbl)	Gas (MMcf)	Mmboe(6:1)
Proved Developed Producing	PDP	**1,434**	**2,348**	**1,825**
Proved behind Pipe	PDBP	**1,801**	**2,601**	**2,235**
Proved Undeveloped	PUD	**5,309**	**18,205**	**8,343**
Proved (1P)	**1P**	**8,544**	**23,154**	**12,403**
Probable Reserves		5,231	7,894	6,547
Proved and Probable (2P)	**2P**	**13,775**	**31,048**	**18,950**
Probable Reserves		4,813	5,364	5,707
Proved, Probable & Possible (3P)	**3P**	**18,588**	**36,412**	**24,657**
Prospective Resources (Best Estimate Unrisked)	**Pr**	**18,350**	**208,186**	**53,048**

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

Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency

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

The following table shows a spilt of Byron's remaining reserves, as at 30 June 2023, into developed and undeveloped categories by project and by product. All of the reserves in this table are located in the shallow water in the Gulf of Mexico, Offshore Louisiana.

Byron Energy Limited – Remaining Reserves Net to Byron

	Developed		Undeveloped		Total
June 30, 2023	Oil Mbbl	Gas MMcf	Oil Mbbl	Gas MMcf	**Boe Mboe (6:1)**
Total					
Proved (1P)	**3,234**	**4,949**	**5,309**	**18,205**	**12,402**
Probable Reserves	1,015	1,209	4,216	6,684	**6,547**
Proved and Probable (2P)	**4,249**	**6,158**	**9,525**	**24,889**	**18,949**
Possible	1,128	1,176	3,687	4,188	**5,709**
Proved, Probable & Possible (3P)	**5,377**	**7,334**	**13,212**	**29,077**	**24,658**

Review of Operations continued

The following table reconciles the movement in Byron's reserves between 30 June 2022 and 30 June 2023.

Byron Energy Limited Reserves (Net to Byron) Net to Byron Gulf of Mexico, offshore Louisiana, USA

	Oil (Mbbl) (Net to Byron)				
Reserves Reconciliation	Remaining	Production	Additions & Revisions	Relinqushments	Remaining
	30/6/2022	**2023**	**2023**	**2023**	**30/6/2023**
Grand Total					
Proved (1P)	**9,594**	**-569**	**-481**	**0**	**8,544**
Probable Reserves	4,228	0	1,004	0	5,232
Proved and Probable (2P)	**13,822**	**-569**	**523**	**0**	**13,776**
Possible Reserves	4,214	0	599	0	4,813
Proved, Probable & Possible (3P)	**18,036**	**-569**	**1,122**	**0**	**18,589**

	Gas (MMcf) (net to Byron)				
Reserves Reconciliation	Remaining	Production	Additions & Revisions	Relinqushments	Remaining
	30/6/2022	**2023**	**2023**	**2023**	**30/6/2023**
Grand Total					
Proved (1P)	**21,657**	**-1,464**	**2,961**	**0**	**23,154**
Probable Reserves	7,060	0	833	0	7,893
Proved and Probable (2P)	**28,717**	**-1,464**	**3,794**	**0**	**31,047**
Possible Reserves	5,115	0	249	0	5,364
Proved, Probable & Possible (3P)	**33,832**	**-1,464**	**4,043**	**0**	**36,411**

Material Changes to Reserves

Net Proved Reserves (1P) at 30 June 2023 were 8.5 MMbl and 23.2 Bcfg, (12.4MMboe), a decrease of approximately 6% compared to 2022 mainly due to the effect of production during the year ended 30 June 2023.

Net Proved and Probable Reserves (2P) at 30 June 2023 were 13.8 MMbl and 31.1 Bcfg (18.9 MMboe), an increase of approximately 2% over 2022 mainly due to the effect of production during the year ended 30 June 2023.more than offset by additions to probable reserves at SM58.

Prospective Resources as at 30 June 2023

The following table shows Byron's prospective resources as at 30 June 2023 compared to 30 June 2022.

Byron Energy Limited Prospective Resources (net to Byron) Gulf of Mexico, offshore Louisiana, USA

Best Estimate Unrisked 30 June 2023	Oil Mbbl	Gas MMcf	Mboe (6:1)
SM 71	977	19,885	4,291
SMI 58	12,196	40,403	18,930
SMI 58/69	545	545	636
GI 63/72	4,632	147,353	29,191
Total Prospective Resources (2023)	**18,350**	**208,186**	**53,048**
Total Prospective Resources (2022)	**23,931**	**297,435**	**73,504**

Material Changes to Prospective Resources

The addition of 4.6 MMbbl and 147.4 Bcfg of Net Prospective Resources at GI63/72 is being evaluated for future drilling.

Notes to Reserves and Resources Statement

Reserves and Resources Governance

Byron's reserves estimates are compiled annually. Byron engages Collarini and Associates, a qualified external petroleum engineering consultant, to conduct an independent assessment of the Company's reserves. Collarini and Associates is and independent petroleum engineering consulting firm that has been providing petroleum consulting services in the USA for more than fifteen years. Collarini and Associates does not have any financial interest or own any shares in the Company. The fees paid to Collarini and Associates are not contingent on the reserves outcome of the reserves report.

Competent Persons Statement

The information in this report that relates to oil and gas reserves and resources was compiled by technical employees of independent consultants Collarini and Associates, under the supervision of Mr Mitch Reece BSc PE. Mr Reece is the President of Collarini and Associates and is a registered professional engineer in the State of Texas and a member of the Society of Petroleum Evaluation Engineers (SPEE), Society of Petroleum Engineers (SPE), and American Petroleum Institute (API). The reserves and resources included in this report have been prepared using definitions and guidelines consistent with the 2007 Society of Petroleum Engineers (SPE)/ World Petroleum Council (WPC)/American Association of Petroleum Geologists (AAPG)/ Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (PRMS). The reserves and resources information reported in this Statement are based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr Reece. Mr Reece is qualified in accordance with the requirements of ASX Listing Rule 5.41 and consents to the inclusion of the information in this report of the matters based on this information in the form and context in which it appears.

Reserves Cautionary Statement

Oil and gas reserves estimates are expressions of judgment based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. This may result in alterations to development and production plans which may, in turn, adversely impact the Company's operations. Reserves estimates and estimates of future net revenues are, by nature, forward looking statements and subject to the same risks as other forward looking statements.

Prospective Resources Cautionary Statement

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 recoverable hydrocarbons.

Forward Looking Statements

This document may contain forward-looking information. Forward-looking information is generally identifiable by the terminology used, such as "expect", "believe", "estimate", "should", "anticipate" and "potential" or other similar wording. Forward-looking information in this document includes, but is not limited to, references to: well drilling programs and drilling plans, estimates of potentially recoverable resources, and information on future production and project start-ups. By their very nature, the forward-looking statements contained in this document require Byron and its management to make assumptions that may not materialise or that may not be accurate. Although Byron believes its expectations reflected in these statements are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements.

Pricing Assumptions

Oil prices used in this report represent actual price received by Byron in the month of July of $76.04 followed by the August 9th, NYMEX West Texas Intermediate (WTI) Strip prices starting on August 1, 2023, of $83.47 per barrel. Beginning January 1, 2024, the Reuters Poll consensus pricing was used with a starting price of $79.16 per barrel, increasing to $80.27 per barrel on January 1, 2025 declining to $72.45 per barrel on January 1, 2026 and with a final price of $66.69 per barrel on January 1, 2027, then held constant thereafter. Gas prices used in this report represent a Henry Hub base August 9th, NYMEX Strip prices starting on July 1, 2023, of $2.96 per MMBtu. Beginning January 1, 2024, the Reuters Poll consensus pricing was used with a starting price of $3.67 per MMBtu, increasing through the period to $4.17 on January 1, 2025 then declining to $3.67 per MMBtu on January 1, 2026, then held constant thereafter. These prices were then adjusted to account for transportation cost, basis difference, Light Louisiana Sweet (LLS) vs WTI oil gravity.

ASX Reserves and Resources Reporting Notes

(i) The reserves and prospective resources in this document are as at 30 June 2023 (Listing Rule (LR) 5.25.1)

(ii) The reserves and prospective resources in this document have been estimated and is classified in accordance with SPE-PRMS (Society of Petroleum Engineers - Petroleum Resources Management System) (LR 5.25.2)

(iii) The reserves and prospective resources in this document are reported according to the Company's economic interest in each of the reserves and prospective resources net of royalties (LR 5.25.5)

(iv) The reserves and prospective resources information in this document has been estimated and prepared using the deterministic method (LR 5.25.6)

(v) The reserves and prospective resources in this document have been estimated using a 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 (LR 5.25.7)

(vi) The reserves and prospective resources in this document have been estimated on the basis that products are sold on the spot market with delivery at the sales point on the production facilities (LR 5.26.5)

(vii) The method of aggregation used in calculating estimated reserves was the arithmetic summation by category of reserves. As a result of the arithmetic aggregation of the field totals, 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 (LR 5.26.7 & 5.26.8)

(viii) Prospective resources are reported on a best estimate basis (LR 5.28.1)

(ix) For prospective resources, 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 hydrocarbons (LR 5.28.2)

Financial Report

For the year ended 30 June 2023

Directors' Report

Your directors submit herewith their report together with the Financial Report of Byron Energy Limited ("the consolidated entity" or "Group"), being Byron Energy Limited ("Byron" or the "Company") and its subsidiaries for the financial year ended 30 June 2023.

Directors

The names and details of the Company's directors in office during the financial year and until the date of this report are as follows:

Douglas G. Battersby

Maynard V. Smith

Prent H. Kallenberger

Charles J. Sands

Paul A. Young

William R. Sack

All directors have held office for the whole year unless otherwise stated.

Names, qualifications, experience and special responsibilities:

Douglas G. Battersby *Non-Executive Chairman* Appointed 18th March 2013	Doug is a petroleum geologist with over fifty years' technical and managerial experience in the Australian and international oil and gas industry. Doug co-founded two ASX listed companies (Eastern Star Gas Limited, which was taken over by Santos Limited in November 2011, and SAPEX Limited, which was taken over by Linc Energy Limited in October 2008), and two private oil and gas exploration/development companies, Darcy Energy Limited, which was sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he was Executive Chairman until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 1990 and 1999 Doug was Technical Director at Petsec Energy Limited, an ASX listed operator in the shallow waters of the Gulf of Mexico with production reaching 100 MMcf per day of gas and 9,000 barrels of oil per day in 1997. Doug holds a Master of Science degree in Petroleum Geology and Geochemistry from Melbourne University. Other current directorships of listed companies None. Former directorships of listed companies in last three years None.
Maynard V. Smith *Executive Director and Chief Executive Officer* Appointed 18th March 2013	Maynard is a geophysicist with approximately fifty years' technical and managerial experience in the oil and gas industry with a particular focus on the Gulf of Mexico. Maynard co-founded Darcy Energy Limited, sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he has been Chief Executive until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Prior to that, Maynard was Chief Operating Officer with Petsec Energy Limited (1989-2000). In the late 1970s and early 1980s Maynard held senior exploration positions with Tenneco Oil Company, based in Bakersfield, California. Maynard holds a Bachelor of Science degree in Geophysics from California State University at San Diego. Other current directorships of listed companies None. Former directorships of listed companies in last three years None.

Prent H. Kallenberger *Executive Director and Chief Operating Officer* Appointed 18th March 2013	Prent is a geoscientist with over forty years' experience in the oil and gas industry with extensive exploration and development experience in the Gulf of Mexico, having generated prospects which have led to the drilling of over one hundred and twenty five wells in the Gulf of Mexico and California. He was Vice President of Exploration with Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 2000 and 2006, Prent was Vice President of Exploration with Petsec Energy Inc, where he was responsible for a team of seven people and generated projects leading to the drilling of ten successful wells in twelve attempts in the shallow waters of the Gulf of Mexico. These wells produced 32 Bcf and 1.5 MMBbls of oil. Between 1992 and 1998 Prent was Geophysical Manager with Petsec Energy Inc, a wholly owned subsidiary of Petsec Energy Limited. He holds a Bachelor of Science degree in Geology from Boise State University and Master of Science degree in Geophysics from Colorado School of Mines. Other current directorships of listed companies None. Former directorships of listed companies in last three years None.
Charles J. Sands *Non-Executive Director* Appointed 18th March 2013	Charles was a non-executive director of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Charles was also a director of Darcy Energy Limited. Charles has over forty years' of broad based business and management experience in the USA and is President of A. Santini Storage Company of New Jersey Inc, enabling him to advise on the general business operating environment and practices in the USA. Charles is also an owner of CAT5 Resources a disaster recovery and maintenance company focused on the cellular telephone industry in the US. He holds a Bachelor of Science degree from Monmouth University. Charles is currently a member of the Audit and Risk Management Committee. Other current directorships of listed companies None. Former directorships of listed companies in last three years None.
Paul A. Young *Non-Executive Director* Appointed 18th March 2013	Paul has been in merchant banking for more than thirty five years. He has extensive experience in the provision of corporate advice to a wide range of Australian and international listed and unlisted companies including restructurings, capital raisings, initial public offerings and mergers and acquisitions. Paul is an Honours Graduate in Economics (University of Cambridge) and has an Advanced Diploma in Corporate Finance. He is a Fellow of the Institute of Chartered Accountants in England and Wales. Paul is currently Chairman of the Audit and Risk Management Committee. Other current directorships of listed companies • Left Field Printing Group Limited, a Hong Kong listed company. Former directorships of listed companies in last three years • Ovato Limited, appointed as a non-executive director in April 2022 and resigned in June 2022; • Ambition Group Limited, voluntarily delisted 30 September 2020 but a continuing director.

Directors’ Report continued

William R. Sack *Executive Director* Appointed 3rd October 2014	Bill is an explorationist with more than thirty five years’ experience in the Gulf of Mexico region in technical, commercial and executive roles. He was appointed to the Board of Directors on 3rd October 2014. Bill’s qualifications comprise BSc. Earth Sci./Physics, MSc. Geology and an MBA. He co-founded and served as Managing Partner of Aurora Exploration, LLC, a private entity focused on generating and drilling Gulf of Mexico exploration opportunities that has drilled more than eighty wells with a success rate in excess of 80%, and under his leadership has created substantial growth and monetised investments via multiple corporate level asset sales. Prior to 2000 he served in a variety of exploration and executive roles for Petsec Energy and Shell Offshore. Bill holds a Bachelor of Science degree in Earth Science/Physics from St. Cloud State University, a Master of Science degree in Geology from Michigan State University and a Master of Business Administration from Tulane University. Other current directorships of listed companies None. Former directorships of listed companies in last three years None.

Summary of shares and options on issue

At 30 June 2023, the Company had 1,081,395,102 ordinary shares, including 41,100,000 shares classified as treasury shares, and 2,000,000 options on issue. Details of the options are as follows:

Issuing entity	Number of shares under option	Class of shares	Exercise price	Expiry date
Byron Energy Limited	2,000,000	Ordinary	A$0.16	31 December 2024
	2,000,000			

During the year ended 30 June 2023, the Company did not issue any fully paid shares, nor any share options over fully paid ordinary shares.

Post 30 June 2023, no ordinary shares, nor share options were issued and no share options were exercised subsequent to 30 June 2023 through to the date of this report.

Shareholdings and option holdings of directors and other key management personnel

The interests of each director and other key management personnel, directly and indirectly, in the shares and options of Byron Energy Limited at the date of this report are as follows:

Director/Key Management Personnel	Ordinary shares	Options over ordinary shares	Exercise price	Option expiry date
D. G. Battersby	57,800,568	0	N/A	N/A
M. V. Smith	49,047,991	0	N/A	N/A
P. H. Kallenberger	12,808,762	0	N/A	N/A
C. J. Sands	24,710,783	0	N/A	N/A
P. A. Young	29,224,397	0	N/A	N/A
W. R. Sack	15,300,001	0	N/A	N/A
N. Filipovic	7,301,359	0	N/A	N/A

Summary of shares and options on issue

During the financial year, no shares or share options were granted to directors or key management personnel of the Company.

Company Secretary

Nick Filipovic

Appointed 18th March 2013.

Nick is a qualified accountant with over forty years' experience in the financial services and natural resources industries, including oil and gas, where he has held a range of senior financial and commercial management positions. He was the Chief Financial Officer and Company Secretary of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Principal activities

The principal activities of the consolidated entity during the financial year were oil and gas exploration, development and production in the shallow waters in the Gulf of Mexico ("GOM"), USA.

Consolidated results

The profit for the consolidated entity after income tax was US$22,715,727 (2022: US$22,215,308).

Review of Operations

Financial summary

The Group recorded a net profit after income tax of US$22,715,727 for the year ended 30 June 2023, compared to a net profit after tax of US$22,215,308 for the year ended 30 June 2022.

Earnings before interest, tax, amortisation, share based payments, impairment, realised oil hedge price losses and depreciation and exploration expense ("EBITDAX") for the year ended 30 June 2023 totalled US$39,341,156, a decrease of 5% compared to US$41,576,783 for the year ended 30 June 2022, primarily as a result of higher lease operating costs, lower realised oil and gas prices, decreased gas production, partially offset by higher oil production.

EBITDAX (US$)	**Year ended 30 June 2023**	**Year ended 30 June 2022**
Profit for the year from continuing operations	**22,715,727**	22,215,308
Net Financial Expenses	**1,465,610**	2,134,651
Depreciation & amortisation	**11,903,146**	12,063,092
Share based payments	**133,026**	1,599,464
Impairment expense and dry hole expense	**3,123,647**	3,082,807
Realised loss on forward commodity price contracts	**–**	481,461
EBITDAX	**39,341,156**	41,576,783

* EBITDAX is a non-GAAP financial measure. The Company believes that this presentation helps investors understand Byron's operating performance and makes it easier to compare its results with those of other companies that have a different financing and capital structure. EBITDAX should not be considered in isolation from or as a substitute for profit from operations.

Production, Prices and Revenue

Net production (sales) for the year ended 30 June 2023 was 575,645 barrels of oil and 1,607,642 mmbtu of gas compared to 516,734 barrels of oil and 2,299,907 mmbtu of gas for the year ended 30 June 2022. The increase in oil production was due the commencement of the production from the SM58 G3 and G5 wells in July/August 2022, a full year's production from the SM69 E2 well and improved SM58 G1 well production following successful downhole work. The decrease in gas production was mainly due to natural decline in gas production from the SM58 wells.

For the year ended 30 June 2023, Byron realised an average crude oil sales price of US$77.22 per barrel (after transportation and quality adjustments) and an average realised gas price of US$4.97 (after transportation and quality adjustments), a decrease of approximately 2% and 1.5% respectively compared to the year ended 30 June 2022 where average prices of US$78.81 per barrel of oil and US$5.05 per mmbtu were realised.

Net revenue (after royalties) for the year ended 30 June 2023 of US$53,019,366 was similar to the US$53,143,411 for the year ended 30 June 2022. The flat result in the 2023 year was driven primarily by increased oil production, offset by lower gas production and lower oil and gas prices.

Byron's share of oil and gas production and sales by field for the 30 June 2023 year, compared to the corresponding period in 2022 is summarised in the table below.

Production (sales)	Year ended 30 June 2023	Year ended 30 June 2022
Net production Byron share (NRI basis) SM71		
Oil (bbls)	**233,426**	319,103
Gas (mmbtu)	**214,390**	271,894
Net production Byron share (NRI basis) SM58		
Oil (bbls)	**324,114**	178,183
Gas (mmbtu)	**1,390,034**	2,024,505
Net production Byron share (NRI basis) SM58 E1 well		
Oil (bbls)	**18,105**	19,448
Gas (mmbtu)	**3,218**	3,508
Total net production (NRI basis)		
Oil (bbls)	**575,645**	516,734
Gas (mmbtu)	**1,607,642**	2,299,907

Cost of sales

Cost of sales, which includes base lease operating expenses, insurance premiums, amortisation and depreciation and gas transportation charges, were US$20,565,589 for the year ended 30 June 2023 compared to US$19,105,413 for the comparable period in 2022. The increase is primarily due to higher lease operating costs due to two additional wells brought on production in July/August 2023, industry wide cost inflation and increased insurance premiums, offset by lower amortisation charges and gas transportation costs reflecting lower gas production.

Corporate and administration costs

Corporate and administration costs were US$3,247,960 for the year ended 30 June 2023, compared to US$2,920,851 for the year ended 30 June 2022, mainly due to increased remuneration expense following an increase in salaries effective 1 January 2023 and generally higher contractor and professional service fees reflecting inflationary cost pressures.

Impairment charges

Impairment charges of US$3,123,647 for the year ended 30 June 2023 were marginally higher than impairment charges for the year ended 30 June 2022 of US$3,082,807. The 2023 impairments charges comprise relinquishments of the Main Pass 293,305, 306 and South Marsh Island 60 & 70 leases, compared to the write off of four Eugene Island blocks and South Marsh Island 57 upon relinquishment in 2022.

Finance costs

Finance costs of US$1,552,666 for the year ended 30 June 2023 was lower than finance costs of US$2,267,466 in 2022 as a result of substantially lower average loan balances during the 2023 year.

Share based payment expenses

Share based payment expenses in the year ended 30 June 2023 were US$133,026 compared to US$1,599,464 share-based payment expenses in the 2022 financial year. Share based payment expenses in the 2022 financial year comprise the expenses in relation to the interest free loans to executive directors, staff and contractors for the funding of the conversion of 41,100,000 share options over unissued shares in the Company which expired on 31 December 2021.

Balance sheet, cash flow and liquidity

At 30 June 2023, the consolidated entity had total assets of US$144,489,683 (30 June 2022: US$151,045,468) and total liabilities of US$16,121,978 (30 June 2022: US$45,533,876) resulting in net assets of US$128,367,705 (30 June 2022: US$105,511,592). The increase in net assets was primarily due to an increase in the written down value of the oil and gas properties (completion of the of SM58 G3 and G5 wells), lower borrowings and prepaid revenues, lower trade and other payables partly offset by lower cash and cash equivalents, lower oil and gas receivables and a reduction in the carrying value of exploration and evaluations assets.

At 30 June 2023, the consolidated entity held cash and cash equivalents of US$4,223,877 (30 June 2022 US$14,087,032).

Borrowings at 30 June 2023 were US$5,586,455 primarily comprising loans from directors and one longstanding shareholder, plus financing of the Company's insurance coverage program.

Borrowings (US$)	30 June 2023	30 June 2022
Promissory note (Crescent Midstream)	–	4,830,114
Directors and shareholder	**3,392,300**	3,446,690
Insurance premium financing	**2,194,155**	1,701,944
Prepaid oil revenue (unearned revenue)	–	11,000,000
Total	**5,586,455**	20,978,748

The reduction in borrowings is due to repayment of the Crescent Promissory Note in line with the agreement and the repayment of prepaid oil revenues during the year ended 30 June 2023.

In June 2023, outstanding borrowings from the directors and/or entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder were extended and as of 30 June 2023 are due to be repaid on 31 March 2025. Subsequent to 30 June 2023, the directors and a shareholder agreed to further extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum effective 1 August 2023 with the additional 2% to be capitalised until loan repayment date of 31 December 2025.

Capital expenditure

Capital expenditure on oil and gas properties for the year ended 30 June 2023 was US$18,170,138 comprising expenditure on the completion and hook up of SM58 G3 and G5 wells in July and August 2022.

Hedging

As at 30 June 2023 the Company did not have any hedges in relation to future production of oil or gas. Subsequent to 30 June 2023, Byron has entered into oil price hedges covering 475 barrels of oil per day as outlined in the significant events after the balance date note.

Operations Update

South Marsh Island 71

The South Marsh Island block 71 ("SM71"), is a lease in the South Marsh Island 73 field ("SM73"). 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 and 81.25% NRI. Water depth in the area is approximately 137 feet.

Net production and sales for the year ended 30 June 2023 from all wells on the SM71 F Platform totalled approximately 233,426 barrels of oil and 214,390 mmbtu of gas (June 2022 year 319,103 barrels and 271,894 mmbtu). Lower production for the 2023 financial year is mainly due to natural oil production decline and high water cut from the F3 well.

As of 30 June 2023, the SM71 F facility has produced approximately 4.6 million barrels of oil ("Mmbo") (gross) since initial production began in March 2018. The facility has also produced approximately 5.5 billion cubic feet of gas ("Bcfg") (gross).

The F1 and F3 wells, produce from the primary D5 Sand reservoir, and the F1 well contributed most of the production during the 2023 financial year, with the F2 well, producing from the B55 Sand, and the F4 well, producing from the Upper J1 Sand, contributing a small amount of production.

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.

Byron has also earned a 100% WI in the SM69 E2 well (E2) under the Joint Exploration Agreement ("JEA") with ANKOR group (now WT Offshore Inc) which provided for the drilling of the E2 exploration well operated by Byron. By funding 100% of the E2 well, Byron earned a 100% WI and 80.33% NRI until E2 Project Payout. Effective 1st January 2023, Byron's 100% WI and 80.33% NRI in the SM69 E2 well was 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% WI, 25% NRI in the E2 well.

Byron's share of net production and sales form the SM58 G platform, comprising SM58 G1, G2, G3 and G5 wells and the SM69 E2 well, and for the year ended 30 June 2023 totalled 1,390,034 mmbtu of gas and 324,114 barrels of oil (June 2022 year 2,024,505 mmbtu of gas and 178,183 barrels of oil).

Oil production for the year ended 30 June 2023 was above the volumes achieved for the 2022 year due to the commencement of the production from the SM58 G3 and G5 wells in July/August 2022, a full year's production from the SM69 E2 well and improved SM58 G1 well production following successful downhole work. The decrease in gas production was mainly due to natural decline in the SM58 wells.

As of 30 June 2023, the SM58 G facility has produced approximately 8.3 Bcfg and 0.73 million barrels of oil and condensate (gross) on a cumulative basis.

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 300 bopd and no formation water. Gas production from the G1 well has continued to follow a natural and predictable pressure decline.

The SM58 G2 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.

Following the successful drilling and completion of the Company's SM69 E2 well, production began on 21 October 2021.

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

South Marsh Island 58 E1 Well bore and SM69 E Platform

Byron owns a 53% WI and a 44.17% NRI in the joint area reservoirs from the surface to a depth of 7,490 feet TVD, located in the S1/2 of the SE1/4 of the SE1/4 of SM58, as well as a 53% working interest in the SM 69 E platform. W&T Offshore Inc (as successor to Ankor Energy, LLC) is the designated operator of this portion of the block to facilitate the surface operatorship of the jointly owned SM 58 E1 well and E platform which is located in the NE corner of the SM 69 block.

The E1 well was drilled from a surface location in SM69 to a bottom hole location in SM58 in 2011 and is completed in the K4 Sand (B65 Sand) and has produced a total of 630,000 barrels of oil, 0.185 bcf of gas and 800,000 barrels of formation water.

The SM58 E1 well produces from the K Sand 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).

For the year ended 30 June 2023, Byron's share of net production was 18,105 barrels of oil and 3,218 mmbtu, compared to 19,448 barrels of oil and 3,508 mmbtu in the 2022 year.

Exploration and Evaluation Assets

OCS Lease sale 259

As reported on 17 April 2023, Byron Energy Inc., a wholly owned subsidiary of the Company, was awarded three leases at Gulf of Mexico, Outer Continental Shelf (OCS) Lease Sale 259 held in New Orleans, Louisiana on Wednesday, 29 March 2023. Byron was awarded Grand Isle Area Blocks 63 and 72 (GI63/72) and South Marsh Island Area Block 57 (SM57).

The Grand Isle blocks represent an additional salt dome project area for the Company and were evaluated using Reverse Time Migration ("RTM") 3D seismic data. Each block has had minor oil and gas production in the past and the RTM data indicates the possibility of remaining exploration and development potential on these blocks. These two blocks are approximately 125 miles east of Byron's current SM58/71 operating areas giving Byron good geographical diversity, in the event of hurricanes, should the Company discover and develop commercial hydrocarbons on these leases.

SM57 is adjacent to the Company's SM58 G platform where Byron operates a total of five active wells. SM57 was relinquished by the Company in 2021, but a recent proprietary seismic reprocessing effort has improved the prospectivity of the previously mapped oil and gas prospects.

South Marsh Island 61 and 66

Byron holds a 100% WI and 87.5% NRI in SM 61 and SM66. Theses leases are in close proximity to Byron's existing SM58 and SM70 platforms and increase Byron's footprint in the South Marsh Island 73 Field. Water depth in the area is approximately 125 feet.

The Company was the apparent high bidder on the South Marsh Island 61 lease ("SM61") at the Gulf of Mexico, Outer Continental Shelf Lease Sale 257 held in New Orleans, Louisiana on Wednesday, 17 November 2021. Byron bid approximately US$130,000 on SM61 (WI 100/NRI 87.50%) which lies within the area of Byron's RTM reprocessing project which was used to evaluate the prospect potential on the block.

Byron was awarded SM61 in September 2022 by the Bureau of Ocean Energy Management.

Portfolio Optimisation

During the year ended 30 June 2023, Byron elected to relinquish the following properties:

(i) Main Pass blocks 293, 305, 306 ("MP306"), and

(ii) South Marsh Island 60 ("SM60") and 70 ("SM70")

During the December 2022 quarter, Byron's technical team completed the interpretation project over Main Pass blocks 293, 305 and 306 ("MP306"). After full evaluation it was determined that several previously identified potential drilling opportunities did not meet the Company's technical and economic risk criteria. Byron relinquished the leases and their carrying values have been written off.

Upon completion of a focussed post-stack seismic reprocessing effort during the March 2023 quarter, over its leasehold in the SM58 project area and as a result of this work, together with significantly reduced gas prices, Byron decided not to drill the SM70 Golden Trout prospect and instead, relinquish the SM70 lease. Consequently, the carrying value was written off.

With only a year to expiry, Byron relinquished the SM60 lease in June 2023. Consequently, the carrying value was written off prior to 30 June 2023.

Properties

As at 30 June 2023, Byron's portfolio of properties under lease in the shallow waters of the Gulf of Mexico, USA comprised:

Properties	Operator	Interest WI/NRI (%)*	Lease Expiry Date	Lease Area (Km²)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/81.25	April 2028	21.98
Block 61	Byron	100.00/87.50	September 2027	20.23
Block 58 (excluding E1 well)	Byron	100.00/83.33**	Production	20.23
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)	Ankor	53.00/44.16667		
SM69 (NE ¼ of NE ¼) (E-2 well)	Byron	70.00/58.33***	Production	1.30
Block 66	Byron	100.00/87.50	December 2025	20.23
Grand Isle				
Block 63	Byron	100.00/81.25	April 2028	20.23
Block 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 ft TVD and 50% WI below 13,639 ft 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.

Review of strategy, principal risks and uncertainties facing the Company

Strategy

Since inception Byron has focused on the shallow waters of the OCS in the GOM. The directors believe that the shallow waters of the GOM offer significant advantages to Byron, as the GOM:

- is a prolific producer of oil and gas;
- has significant proved and unproved reserves of low cost oil and gas as well as significant potential for further hydrocarbon discoveries;
- has extensive, established and accessible oil and gas exploration, development and production infrastructure;
- offers a short development cycle and rapid payback;
- has modern 3D seismic coverage, suitable for improved imaging, over fields and prospects, available for purchase from third party providers;
- advanced seismic processing techniques have allowed the industry to better distinguish hydrocarbon traps and identify previously unknown prospects; and
- has a well-established and stable administration with one landowner for the shallow waters, BOEM.

Byron is well positioned to exploit the competitive advantages of the GOM as the Company has:

- an experienced team of oil and gas exploration, development and production personnel with a successful track record in the GOM, with significant experience utilising advanced seismic image processing techniques, including reverse time migration, in Byron's area of focus;
- two Byron operated, producing and cash generating assets, SM71 and SM58;
- an inventory of relatively low risk, ready to drill prospects, including several prospects with significant oil potential; and
- the capacity to grow its asset portfolio in the shallow waters and transition zone of the GOM.

Byron's strategy in the GOM comprises three key elements:

- to identify highly prospective oil and gas plays, aided by leading edge seismic technology such as RTM, which is particularly effective in the shallow waters of the GOM;
- to secure the leases, usually on a 100% or majority working interest basis; and
- Byron will either 'drill test' the play as operator holding a 100% working interest or seek to farm out up to 50% of its WI to a non-operator or another operator with a proven track record of drilling and producing wells in the GOM, retaining a 40-50% WI in the block.

Principal Risks and Uncertainties

The key areas of risk, uncertainty and material issues facing the Company in executing its strategy and delivering on its targets are described below.

Risks relating to the Company's industry, business and financial condition

There are a number of risks which may impact on the operating and financial performance of the Company and therefore, on the value of its shares. Some of these risks can be mitigated by the Company's systems and internal controls, but many are outside of the control of the Company and the Board. There can be no guarantee that the Company will achieve its stated objectives or that any forward-looking statements will eventuate.

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to the Company and the oil and gas industry could materially impact the Company's future performance and results of operations. Below is a list of known material risk factors that should be reviewed when considering buying or selling Byron's shares. These are not all the risks the Company faces and other factors currently considered immaterial or unknown may impact future operations.

Inflationary risk

Cost inflation, including significant increases in raw materials costs, labor rates, and domestic transportation costs have and could continue to impact profitability. Such cost increases did not materially impact the Company's 2023 operating results and financial condition or results, there is no guarantee that the Company can reduce costs to fully mitigate the effect of inflation on its cost base and business, which may adversely impact future sales margins and profitability.

Oil and natural gas price risk

The Company's revenues, profitability and future growth depend significantly on crude oil and natural gas prices. Oil and natural gas prices are volatile and low prices could have a material adverse impact on cash flow and on Byron's business. Among the factors that can cause these fluctuations are: (i) changes in global supply and demand for oil and natural gas, (ii) the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls, (iii) the price and volume of imports into the USA of foreign oil and natural gas, (iv) political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity (v) the level of global oil and gas exploration and production activity, (vi) weather conditions, (vii) technological advances affecting energy consumption, (viii) USA domestic and foreign governmental regulations and taxes, (ix) proximity and capacity of oil and gas pipelines and other transportation facilities, (x) the price and availability of competitors' supplies of oil and gas in captive market areas, (xi) the introduction, price and availability of alternative forms of fuel to replace or compete with oil and natural gas, (xii) import and export regulations for LNG and/or refined products derived from oil and gas production from the USA, (xiii) speculation in the price of commodities in the commodity futures market, (xiv) the availability of drilling rigs and completion equipment; and the overall economic environment.

Financing risk

Byron's business plan, which includes participation in seismic data purchases, lease acquisitions and the drilling of exploration and development prospects, has required and is expected to continue to require capital expenditures. Byron may require additional financing to fund its planned growth. This additional financing may be in the form of equity, debt or a combination thereof. Byron may also obtain capital by farming out part of its working interest in one or more of its oil and gas properties. Byron's ability to raise additional capital will depend on the results of its operations and the status of various capital and industry markets at the time it seeks such capital. Accordingly, additional financing may not be available on acceptable terms, if at all. In the event additional capital resources are unavailable, Byron may be required to curtail its exploration and development activities. It is difficult to quantify the amount of financing Byron may need to fund its planned growth in the longer term. The amount of funding Byron may need in the future depends on various factors, including but not limited to; (i) the Company's financial condition, and (ii) the success or otherwise of its exploration and development programme. Further, the availability of such funding may depend on various factors, including but not limited to, the liquidity of the Company's shares at the time the Company seeks to raise funds and the prevailing and forecast market price of oil and natural gas. If Byron raises additional funds through the issue of equity securities, this may dilute the holdings of existing shareholders. If Byron obtains additional capital by farming out part of its working interest in one or more of its oil and gas properties, the Company's share of reserves, future production and therefore oil and/or and gas revenues, if any, from those properties will be reduced.

Third party pipelines and operators' risk

Byron may from time to time, depend on third party platforms and pipelines that provide processing and delivery options from its facilities. As these platforms and pipelines are not owned or operated by Byron, their continued operation is not within Byron's control. Revenues in the future may be adversely affected if Byron's ability to process and transport oil or natural gas through those platforms and pipelines is impaired. If any of these platform operators ceases to operate their processing equipment, Byron may be required to shut in the associated wells, construct additional facilities or assume additional liability to re-establish production.

Oil and gas reserves estimation risk

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond the control of the Company. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves. In order to prepare these estimates, Byron's independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyse available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control and may prove to be incorrect over time. As a result, estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in the Company's reserve report have produced for a relatively short period of time. Accordingly, some of the Company's reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect the Company's financial condition, future prospects and market value.

Oil and gas reserves depletion risk

Byron's future oil and natural gas production depends on its success in finding or acquiring new reserves. If Byron fails to replace reserves, its level of production and cash flows will be adversely impacted. Production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Byron's total proved reserves will decline as reserves are produced unless it can conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

Further, all of Byron's proved reserves are proved developed producing or behind pipe. Accordingly, Byron does not have significant opportunities to increase production from its existing proved reserves. Byron's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Byron may not be successful in exploring for, developing or acquiring additional reserves. If Byron is not successful, its future production and revenues will be adversely affected.

Oil and gas drilling risk

Drilling for crude oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect the Company's business, financial condition or results of operations.

The drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, Byron's drilling and producing operations may be curtailed, delayed or cancelled as a result of other factors, including, unusual or unexpected geological formations and miscalculations; pressures; fires; explosions and blowouts; pipe or cement failures; environmental hazards; such as natural gas leaks; oil spills; pipeline and tank ruptures; encountering naturally occurring radioactive materials and unauthorized discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment; loss of drilling fluid circulation; title problems; facility or equipment malfunctions; unexpected operational events; shortages of skilled personnel; shortages or delivery delays of equipment and services; compliance with environmental and other regulatory requirements; natural disasters; and adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; and regulatory fines or penalties.

Operating risk

The oil and natural gas business, including production activities, involves a variety of operating risks, including blowouts, fires and explosions; surface cratering; uncontrollable flows of underground natural gas, oil or formation water; natural disasters; pipe and cement failures; casing collapses; stuck drilling and service tools; reservoir compaction; abnormal pressure formation; environmental hazards such as natural gas leaks, oil spills, pipeline and tank ruptures or unauthorised discharges of brine, toxic gases or well fluids; capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which Byron has no control; repeated shut-ins of Byron's well bores could significantly damage the Company's well bores; required workovers of existing wells that may not be successful.

If any of the above events occur, Byron could incur substantial losses as a result of injury or loss of life; reservoir damage; severe damage to and destruction of property or equipment; pollution and other environmental and natural resources damage; restoration, decommissioning or clean-up responsibilities; regulatory investigations and penalties; suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If Byron was to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect its ability to conduct operations. In accordance with customary industry practices, Byron maintains insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The Company may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on the Company's financial position and results of operations.

Execution risk (drilling and operating programmes)

Shortages or increases in the cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect Byron's operations which could have a material adverse effect on its business, financial condition and results. Where Byron is the operator it assumes additional responsibilities and risks. As the designated operator, Byron, under the BOEM regulations, will be required to post bonds for exploration and development activities as well as for production activities and future decommissioning obligations. There is the risk that the Company may not be able to obtain sufficient bonding and may have to collateralise obligations with cash. If the Company was unable to provide such bonds, it would not be able to proceed with its operating plans. In addition, as the designated operator Byron will have to demonstrate the required oil spill financial responsibility ("OSFR") under the Oil Pollution Act of 1990. The OSFR is based on worst case oil-spill discharge volume. Byron expects to demonstrate OSFR requirement through the purchase of OSFR insurance coverage, a method of demonstrating OSFR acceptable to the BOEM. If the Company was unable to demonstrate OSFR as required by the BOEM, it would not be able to proceed with its operating plans.

Geographic concentration risk

The geographic concentration of Byron's properties in the shallow waters in the GOM means that some or all of the properties could be affected by the same event should the Gulf of Mexico experience severe weather, delays or decreases in production, changes in the status of pipelines, delays in the availability of transport and changes in the regulatory environment.

Because all of the Company's properties could experience the same condition at the same time, these conditions could have a relatively greater impact on results of operations than they might have on other operators who have properties over a wider geographic area.

Climate change risk

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of Greenhouse Gases ("GHG"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. At the federal level, the U.S. Congress has from time to time considered climate change legislation, but no comprehensive climate change legislation has been adopted. The Environmental Protection Authority ("EPA"), however, has adopted regulations under the existing Clean Air Act to restrict emissions of GHG. For example, the EPA imposes preconstruction and operating permit requirements on certain large stationary sources that are already potential sources of certain other significant pollutant emissions. The EPA also adopted rules requiring the monitoring and reporting of GHG emissions on an annual basis from specified large GHG emission sources in the United States, including onshore and offshore oil and natural gas production facilities. Federal agencies have also begun directly regulating emissions of methane, a GHG, from oil and natural gas operations as described above. Compliance with these rules or other could result in increased compliance costs on Byron's operations.

At the international level, the United Nations sponsored Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction goals every five years after 2020. On January 20, 2021 President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on February 19, 2021.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risks in the United States. On January 27, 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the elimination of subsidies provided to the fossil fuel industry, increased production of offshore wind energy and increased emphasis on climate-related risks across governmental agencies and economic sectors.

The Biden Administration has also taken actions to limit oil and gas development activities on the OCS. Other actions that could be pursued by the Biden Administration include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as more stringent emissions standards for oil and gas facilities. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. While Byron's business is not a party to any such litigation, the Company could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact Byron's operations and could have an adverse impact on its financial condition.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption of legislation or regulatory programs to reduce or eliminate future emissions of GHG could require Byron to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas Byron produces. Consequently, legislation and regulatory programs to reduce or eliminate future emissions of GHG could have an adverse effect on Byron's business, financial condition and results of operations. Also, political, financial and litigation risks may result in Byron restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes or impairing the ability to continue to operate in an economic manner.

Some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Byron's offshore operations are particularly at risk from severe climatic events. If any such effects of climate changes were to occur, they could have an adverse effect on the Company's financial condition and results of operations.

Finally, the growth of alternative energy supply options, such as renewables and nuclear, could also present a change to the energy mix that may reduce the value of oil and gas assets.

Competition risk

Competition in the oil and natural gas industry is intense which may make it more difficult for Byron to acquire further properties, market oil and gas and secure trained personnel. There is also competition for capital available for investment, particularly since alternative forms of energy have become more prominent. Most competitors possess and employ financial, technical and personnel resources substantially greater than those available to Byron. As a result increased costs of capital could have an adverse effect on Byron's business.

Environmental risk

The natural gas and oil business involves a variety of operating risks, including but not limited to (i) blowouts, fires and explosions, (ii) surface cratering, (iii) uncontrollable flows of underground natural gas, oil or formation water and natural disasters. If any of the above events occur, Byron could incur losses as a result of injury or loss of life, reservoir damage, damage to and destruction of property or equipment, pollution and other environmental damage, clean-up responsibilities and regulatory investigations and penalties.

The operation of our future oil and gas properties will be subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of the operations of our properties, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

Among the environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and the Company's business are the following: Waste Discharges, Air Emissions and Climate Change, Oil Pollution Act, National Environmental Policy Act, Worker Safety, Safe Drinking Water Act, Offshore Drilling, Hazardous Substances and Wastes and Protected and Endangered Species.

Oil and gas transport and processing risk

All of Byron's oil and natural gas is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or Byron's transportation capacity is materially restricted or is unavailable in the future, the Company's ability to market its oil and/or natural gas could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on its financial condition and results of operations. Further, repeated shut-ins of Byron's wells could result in damage to its well bores that would impair its ability to produce from these wells and could result in additional wells being required to produce existing reserves.

Exchange rate risk

The functional currency of Byron is Australian dollars and the functional currency of its United States based subsidiaries is United States dollars. Byron has historically presented its financial statements in United States dollars, as the United States dollar is viewed as the best measure of performance for Byron because oil and gas, the dominant sources of revenue, are priced in United States dollars and its oil and gas operations are located in the United States with costs incurred in United States dollars.

As all Byron's operating assets are in the United States, the Company's presentation currency, the currency in which it reports its financial results, will be United States dollars. Accordingly, an Australian dollar investment in the Company is exposed to fluctuations between the Australian dollar and the United States dollar exchange rate. In particular, as most of the Company's capital and operating expenses will be in United States dollars any appreciation/depreciation in the Australian dollar against the United States dollar will effectively decrease/increase the quantum of those costs for Shareholders. In addition, the Company's revenue is derived from United States dollar oil and gas sales. Any appreciation/depreciation of the Australian dollar against the United States dollar will effectively reduce/increase the value of that revenue for shareholders.

Adverse exchange rate variations between the Australian dollar and the United States dollar may impact upon cash balances held in Australian dollars. Since most of Byron's operations are conducted in United States dollars, Byron generally maintains a substantial portion of its cash balances in United States dollar accounts. From time to time the Company may have substantial cash deposits in Australian dollar accounts. Until these funds are converted into United States dollars, the United States dollar value of the deposits will change as the exchange rate between the two currencies fluctuates.

The Company does not currently have in place any foreign exchange hedging arrangements. However, foreign exchange hedging strategies will be reviewed by the Company from time to time, implementation of any strategy will depend, inter alia, upon the foreign exchange hedging options available to the Company from time to time, the cash cost of entering into hedging transactions and the Company's capacity to pay for such costs.

Key management risk

To a large extent, the Company depends on the services of its senior management. The loss of the services of any of the senior management team, could have a negative impact on the Company's operations. Byron does not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals.

Regulatory risk

Byron's oil and gas operations in the Gulf of Mexico, USA are subject to regulation at the USA federal, state and local level and some of the laws, rules and regulations that govern operations carry substantial penalties for non-compliance. Rules and regulations affecting the oil and gas industry are under constant review for amendment or expansion. In addition to possible increased costs, the imposition of increased regulatory based procedures may result in delays in being able to initiate or complete drilling programmes.

For offshore operations, lessees must obtain Bureau of Ocean Energy Management ("BOEM") approval for exploration, development and production plans prior to the commencement of their operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency ("EPA"), lessees must obtain a permit from Bureau of Safety and Environmental Enforcement ("BSEE') prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, P&A of wells on the Outer Continental Shelf ("OCS'), calculation of royalty payments and the valuation of production for this purpose, and decommissioning of facilities, structures and pipelines.

President Biden issued an executive order in January 2021 suspending federal offshore and onshore oil and gas leasing pending review and reconsideration of federal oil and gas leasing and permitting practices. After legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021 and a permanent injunction in August 2022, effectively halting implementation of the leasing suspension with respect to those leases cancelled or postponed prior to March 24, 2021. The federal government and a coalition of environmental groups are appealing the district court decision but, in the interim, BOEM scheduled a lease sale for certain blocks in the U.S. Gulf of Mexico consistent with the preliminary injunction, which sale occurred in November 2021. However, on January 27, 2022, a D.C.

District Court judge vacated the lease sale on the basis that BOEM failed to consider the impact on foreign greenhouse gas emissions if the November 2021 lease sale was not held and the court determined that this failure was a violation of the National Environmental Policy Act. However, in September 2022, BOEM announced that it was reinstating the lease results in line with congressional direction in the Inflation Reduction Act of 2022 (the "IRA 2022"). Separately, the Department of Interior (DOI) released its report on federal oil and gas leasing and permitting practices in November 2021, following a review of the onshore and offshore federal oil and gas program.

The report states an intent to modernize the federal oil and gas leasing program and, in respect of the offshore sector, recommends strengthening financial assurance coverage amounts that are more protective of the Federal Government and taxpayers and establishing a "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate on the OCS. The IRA 2022 responded to one of the report's recommendations and increased onshore royalty rates to 16.7% and offshore royalty rates to no less than 16.7% but not more than 18.8% for the next ten years, thereby ensuring the full value of the leased tracts are captured. Several of the report's other recommendations, however, require further action by the Congress and cannot be implemented unilaterally by the Biden Administration and, thus, the extent to which the Biden Administration will act upon the report's recommendations cannot be predicted at this time

In addition, in order to cover the various decommissioning obligations of lessees on the OCS, the BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. In August 2021, the BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder in respect of any new, more stringent, Notice to Lessees or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of non-performance of the interest holder's decommissioning liabilities.

Seismic risk

3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically.

Lease termination risk

The failure to timely effect all lease related payments could cause the leases to be terminated by the BOEM.

Working interest partners' risk

If partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of Byron's reserves and production, which could have a materially adverse effect on its financial condition and results of operations.

Profitability and impairment write-downs risk

Byron may incur non-cash impairment charges in the future, which could have a material adverse effect on its results of operations for the periods in which such charges are taken.

Bonding risk

As an operator, Byron is required to post surety bonds of US$200,000 per lease for exploration and US$500,000 per lease for developmental activities as part of its general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, decommissioning obligations. A failure by an operator to post required supplemental bonding or other financial assurances required by the BOEM could result in the BOEM assessing monetary penalties or requiring any operations on an operator's federal lease to be suspended or cancelled or otherwise subject an operator to monetary penalties. Any one or more such actions imposed onus could materially adversely affect Byron's financial condition and results of operations.

Cyber security risk

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, companies depend on digital technologies to interpret seismic data, conduct reservoir modelling and record financial and other data. The Company also depends on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with its employees and business partners, analyse seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to its business.

The Company's business partners, including vendors, service providers, co-venturers, product purchasers, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorised access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites.

The Company's technologies, systems, networks, and those of its business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorised release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of the Company's business partners, could disrupt its business plans and negatively impact operations. Although to date, Byron has not experienced any material cyber-attacks, there can be no assurance that the Company will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, Byron may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities

Level of indebtedness risk

Byron's utilises debt to fund its operations from time to time. The covenants in future loan agreements, including the US$22 million through a multi-draw loan revenue prepayment facility entered into subsequent to 30 June 2023 governing the Company's debt could negatively impact the Company's financial condition, results of operations and business prospects. Byron's level of indebtedness could affect its operations in several ways, including the following:

- a significant portion or all of cash flows, when generated, could be used to service indebtedness;
- a high level of indebtedness could increase vulnerability to general adverse economic and industry conditions; and
- the covenants contained in the Promissory Note will inter-alia limit ability to borrow additional funds and dispose of assets.

Hedging activities risks

To achieve more predictable cash flows and to reduce exposure to adverse fluctuations in the prices of oil and natural gas, the Company has in the past and may in the future enter into hedging arrangements for a portion of oil and natural gas production, including, forward sale agreements and derivatives such as puts, collars and fixed-price swaps. Changes in the fair value of derivative instruments are recognized in earnings. Accordingly, earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose the Company to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price and actual prices received in the derivative instrument.

In addition, hedging arrangements may limit the benefit the Company could receive from increases in the prices for oil and natural gas and may expose the Company to cash margin requirements in certain cases.

Asset retirement obligations (AROs) risk

Byron is required to record a liability for the present value of AROs to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment and to restore land and seabed when production finishes. Estimating future costs is uncertain because most obligations are many years in the future, regulatory requirements will change and technologies are evolving which may make it more expensive to meet these obligations.

Insurance risk

In accordance with industry practice Byron maintains insurance against some, but not all, of the operating risks to which its business is exposed. Byron will not be insured against all potential risks and liabilities. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable.

Epidemic or outbreak of an infectious disease risk

Byron faces risks related to epidemics, outbreaks or other public health events that are outside of its control, and could significantly disrupt operations and adversely affect the Company's financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to the Company's business and operational plans, which may include but is not limited to (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) restrictions imposed by government and health authorities, including quarantines, to address an outbreak and (v) restrictions imposed by the Company's contractors and customers, including facility shutdowns, to ensure the safety of employees.

In addition, the effects of COVID-19 and concerns regarding its global spread could negatively impact the domestic and international demand for crude oil and natural gas, which could contribute to price volatility, impact the price Byron receives for oil and natural gas and materially and adversely affect the demand for and marketability of our production. The potential impact from COVID-19, both now and in the future, is difficult to predict, and the extent to which it may negatively affect Byron's operating results or the duration of any potential business disruption is uncertain. Any potential impact will depend on future developments and new information that may emerge regarding the COVID-19 infection rate or the efficacy and distribution of COVID-19 vaccines, and the actions taken by authorities to contain it or treat its impact, all of which are beyond the Company's control. These potential impacts, while uncertain, could adversely affect the Company's operating results.

ESG Risks

Increasing attention to climate change, societal expectations for companies to address climate change, investor and societal expectations regarding voluntary Environmental, Social and Governance (ESG) disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for the oil and natural gas we produce, reduced profits, increased risks of governmental investigations and private party litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts from oil and natural gas products and bias against companies operating in the sector. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors. The Company's current ESG governance structure may not allow it to adequately identify or manage ESG related risks and opportunities, which may include failing to achieve ESG-related strategies and goals.

Organizations that provide information to investors on corporate governance, climate change, health and safety and other ESG related factors have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment decisions. Unfavourable ESG ratings and recent activism directed at shifting funding away from companies with fossil energy-related assets could lead to increased negative investor sentiment toward the Company or its customers and to the diversion of investment to other industries, which could have a negative impact on the Company's share price and/or its access to and costs of capital.

Share market investment risk

The Company's shares are quoted on the ASX, where their price may rise or fall. The shares carry no guarantee in respect of profitability, dividends or return of capital, or the price at which they may trade on the ASX. The value of the shares will be subject to the market and hence a range of factors outside of the control of the Company and the directors and officers of the Company. Returns from an investment in the shares may also depend on general share market conditions, as well as the performance of the Company

Historically, the stock market has experienced significant price and volume fluctuations. Stock market volatility and volatility in commodity prices has had a significant impact on the market price of securities issued by many companies, including companies in the oil and gas industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of the Company's shares could fluctuate based upon factors that have little or nothing to do with Byron, and these fluctuations could materially reduce its share price.

Historically, the Company has not paid dividends. Any payment of future dividends will be at the discretion of the board of directors and will depend on, among other things, earnings, financial condition, capital requirements, level of indebtedness and other considerations that the board of directors deems relevant.

Future sales or the availability for sale of substantial amounts of the Company's shares in the public market could adversely affect the prevailing market price of Byron's shares and could impair its ability to raise capital through future issues of equity securities.

Significant events after the balance date

There has been no matter or circumstance since 30 June 2023 which has significantly affected or may significantly affect the operations of the consolidated entity, the results of those operations or the state of affairs of the consolidated entity in subsequent financial years other than those described below:

- on 1 August 2023, Byron announced to the ASX that: (i) it had closed a forward sale loan facility ("Prepayment Facility") for up to US$22 million with a supermajor, Byron's sole purchaser of oil and primary hedge counterparty, to fund the upcoming SM58 development program expected to commence in mid-August 2023 pending rig release by the current operator; (ii) The US$31 million development program is to be funded by a combination of internally generated funds and the US$22 million loan facility provided by the lender, and (iii) The multi-draw facility includes a US$10 million initial draw prior to September 30th followed by an optional second draw of up to US$12 million within 90 days intended to fund completion activities contingent upon success;
- the outstanding directors' and shareholder loans of approximately US$3.4 million, were extended from March 2025 to 31 December 2025; subsequent to 30 June 2023, the directors and a shareholder agreed to further extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum affective 1 August 2023 with the additional 2% to be capitalised until loan repayment date of 31 December 2025;
- On 14 August 2023, Byron announced to the ASX that the Enterprise 264 jack-up drilling rig was on location preparing to drill two wells, Tiger Trout (G4) and Gila Trout (G6) in SM58;
- On 28 August 2023, Byron released its annual reserves report;
- On 8 September 2023, Byron announced that the SM58 G6 well was drilled to 10,465 feet MD/8,667 feet TVD and logged two oil sands with the L2 Sand, logging 32 feet MD net oil and gas pay (23 feet TVT) and the I1 Sand logging 12 feet MD oil pay (10 feet TVT); and
- On 15 September 2023 Byron announced it had received the first draw of US$ 10 million under the Prepayment Facility and had entered into oil price hedges comprising:
  - (i) Hedge 1 – 250 bopd over a period of 24 months (September 2023- August 2025) at an average West Texas Intermediate (WTI) base price of approximately US$74.68, with this average price to be paid each month of the period; and
  - (ii) Hedge 2 – 225 bopd over a period of 23 months from 31 October, 2023 – 31 August, 2025 at an average WTI base price of approximately US$75.00/bopd to be paid at the contracted monthly strip price during the period; and
- On 25 September 2023, Byron announced that the SM58 G4 well was drilled to 10,169 feet MD/9,017 feet TVD and logged an oil sand with the K4(B65) sand target, logging 82 feet MD net oil pay (59 feet TVT).

Future developments

It is expected that the consolidated entity will continue its oil and gas exploration, development and production activities in the shallow waters of the Gulf of Mexico, USA.

Further information regarding likely developments are not included in this report. As the Company is listed on the Australian Securities Exchange ("ASX"), it is subject to the continuous disclosure requirements of the ASX Listing Rules which require immediate disclosure to the market of information that is likely to have a material effect on the price or value of Byron Energy Limited's securities.

Dividends

No dividends in respect of the current financial year have been paid, declared or recommended for payment (2022: nil).

Environmental regulation

The consolidated entity's operations are not regulated by any significant environmental regulation under a law of the Commonwealth or of any State or Territory of Australia. The consolidated entity's oil and gas exploration activities are subject to significant environmental regulation under United States of America Federal and State legislation.

The Directors are not aware of any breach of environmental compliance requirements relating to the consolidated entity's activities during the year.

Non-audit services

Deloitte Touche Tohmatsu did not provide non-audit services to the Company during the financial year.

Auditor independence declaration

A copy of the auditor's independence declaration under s.307C of the *Corporation Act 2001* in relation to the audit of the full year is included in this report.

Indemnification and insurance of officers and auditors

During the financial year the Company paid an insurance premium in respect of Directors' and Officers' liability for the current directors and officers including the company secretary. Under the terms of the policy the premium amount, coverage and other terms of the policy have been agreed to be confidential and not to be disclosed.

The Company has not otherwise, during or since the financial year, except to the extent permitted by law, indemnified or agreed to indemnify an officer or auditor of the Company or of any related body corporate against a liability incurred as such an officer or auditor.

Significant changes in the state of affairs

During the financial year, there were no significant changes in the state of affairs of the consolidated entity, other than those set out in the Review of Operations.

Directors' meetings

The charter for the Audit and Risk Management Committee was adopted on 12 July 2007 and most recently amended on 25 June 2014. The current members of the committee consist of Paul Young (Chairman) and Charles Sands.

During the year there was four Board meetings and four Audit and Risk Management Committee meetings held. The numbers of meetings attended by each director were as follows:

	Board of directors		Audit and Risk Management Committee	
Directors	**Entitled to attend**	**Attended**	**Entitled to attend**	**Attended**
Douglas G. Battersby	4	4	–	–
Maynard V. Smith	4	4	–	–
Prent H. Kallenberger	4	4	–	–
Charles J. Sands	4	3	4	4
Paul A. Young	4	4	4	4
William R. Sack	4	4	–	–

Remuneration report – audited

This remuneration report, which forms part of the directors' report, sets out information about the remuneration of the Group's directors and other key management personnel for the financial year ended 30 June 2023. The prescribed details for each person covered by this report are detailed below.

Details of directors and other key management personnel

Directors and other key management personnel of the Company during and since the end of the financial year are as follows:

Directors

Douglas G. Battersby

Maynard V. Smith

Prent H. Kallenberger

Charles J. Sands

Paul A. Young

William R. Sack

Key management personnel

Nick Filipovic – Chief Financial Officer and Company Secretary

The remuneration report is set out below under the following main headings:

A. Principles and agreements; and

B. Remuneration of directors and other key management personnel

A. Principles and agreements

Remuneration levels are set to attract and retain appropriately qualified and experienced directors and executives. The board is responsible for remuneration policies and practices. The board may seek independent advice on remuneration policies and practices, including compensation packages and terms of employment.

The directors' and key management personnel remuneration levels are not directly dependent upon the Company or consolidated entity's performance or any other performance conditions.

Directors' remuneration is inclusive of committee fees.

Additional information

The Corporations Act requires disclosure of the Company's remuneration policy to contain a discussion of the Company's earnings and performance and the effect of the Company's performance on shareholder wealth in the reporting period and the four previous financial years. The table below provides a five year financial summary.

	30 June 2019 US$	30 June 2020 US$	30 June 2021 US$	30 June 2022 US$	30 June 2023 US$
Revenue (net of royalties)	31,324,061	21,402,255	35,837,228	53,143,411	**53,019,366**
Net profit before tax	5,718,988	68,348	5,854,375	22,215,308	**22,715,727**
Net profit after tax	5,718,988	68,348	5,854,375	22,215,308	**22,715,727**
Share price at start of year	A$0.335	A$0.29	A$0.14	A$0.10	**A$0.17**
Share price at end of year	A$0.29	A$0.14	A$0.10	A$0.17	**A$0.07**
Basic earnings per share	US$0.0083	US$0.000088	US$0.005633	US$0.02135	**US$0.02184**
Diluted earnings per share	US$0.0080	US$0.000086	US$0.005587	US$0.02096	**US$0.02101**

(i) Non-executive directors

The ASX Listing Rules provide that the aggregate remuneration of non-executive directors shall be determined from time to time by a general meeting of shareholders. The latest determination was at the extraordinary general meeting held on 22 April 2013 when shareholders approved an aggregate remuneration of A$300,000 per annum.

The amount of aggregate remuneration has to be approved by shareholders and the fee structure is reviewed annually and no increase to individual non-executive remuneration has been made since 2013.

The Chairman, Douglas Battersby, is paid an annual non-executive director's fee of A$80,000, paid pro-rata on a quarterly basis, as well as reimbursement of costs relating incurred by him in his performance of his duties as a director.

Non-executive directors, Charles Sands and Paul Young, are paid an annual non-executive director's fee of A$40,000 each, paid pro-rata on a quarterly basis, as well as reimbursement of costs incurred by them relating to their performance as directors.

There are no termination or retirement benefits for non-executive directors (other than statutory superannuation where applicable).

(ii) Executive directors and key management personnel

Remuneration levels of executive directors and key management personnel are set to attract and retain appropriately qualified and experienced directors and executives. This involves assessing the appropriateness of the nature and amount of remuneration on a periodic basis by reference to market conditions, length of service and particular experience of the individual concerned.

While the remuneration packages may include a mix of fixed and variable remuneration, short and long term performance based incentives. The remuneration packages are reviewed annually by the board as required.

Currently the remuneration package comprises fixed cash payments.

The board may at its discretion, put in place short term incentive scheme with amounts and basis to be determined by the board. The board may also issue options over unissued shares to executives from time to time, at the discretion of the board and subject to shareholder approval as a form of a long term incentive scheme.

Remuneration and other terms of employment of the Chief Executive Officer (Maynard Smith), Executive Director and Chief Operating Officer (Prent Kallenberger), Executive Director (William Sack) and the CFO/Company Secretary (Nick Filipovic) are detailed below.

Fixed remuneration for executive directors and key management personnel

Maynard Smith

The Company extended its service agreement with Maynard Smith via a company of which Mr Smith is a director effective 16 September 2021 for a period of further three years, at an initial annual rate of A$605,000 plus reasonable and justifiable business expenses, with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by either party "for cause" immediately on notice and otherwise "without cause" on 90 days' notice

Effective 1 January 2023, the annual service fee was increased from A$695,750 to A$765,325.

In addition, Mr Smith is eligible to participate in the Company's short and long term incentive scheme as determined by the Board from time to time.

Prent Kallenberger

The Company extended employment agreement with Prent Kallenberger for a further three years effective on 16 September 2021 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by the Company "for cause" immediately on notice and otherwise "without cause" on 90 days' notice. Under the agreement, Mr Kallenberger's initial remuneration was US$385,000 per annum in fixed remuneration plus medical insurance.

Effective 1 January 2023, Mr Kallenberger's remuneration was increased from US$442,750 to US$487,025.

In addition, Mr Kallenberger is eligible to participate in the Company's short and long term incentive scheme as determined by the Board from time to time.

William Sack

The Company extended its employment agreement with William Sack for a further three years effective 16 September 2021 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of three years. The contract is further terminable by the Company "for cause" immediately on notice and otherwise "without cause" on 90 days; notice. Under the agreement Mr Sack's initial remuneration was US$385,000 plus medical insurance and reasonable and justifiable business expenses.

Effective 1 January 2023, Mr Sack's remuneration was increased from US$442,750 to US$487,025.

In addition, Mr Sack is eligible to participate in the Company's short and long term incentive scheme as determined by the Board from time to time.

Nick Filipovic

The Company has a letter agreement with Nick Filipovic. Under Mr Filipovic's letter of engagement, he is entitled to a gross salary of A$417,450 per annum plus superannuation at the statutory rate. Byron may terminate Mr Filipovic's employment at any time by giving 90 days' notice or in case of serious misconduct employment may be terminated without notice. Should Mr Filipovic resign from Byron he will need to give 90 days' notice.

Effective 1 January 2023, Mr Filipovic's base remuneration was increased from A$379,500 to A$417,450.

In addition, Mr Filipovic is eligible to participate in the Company's short and long term incentive scheme as determined by the Board from time to time.

B. Remuneration of directors and key management personnel

Options

No share options were granted to the executive directors or key management personnel during the financial year and there are no Employee Share Option plans in place.

(i) In January 2020 the Company provided unsecured 3 year interest free loans to the executive directors to fund the acquisition of the shares issued as a consequence of the exercise of options. The interest free loans were approved by shareholders at the Company's 2019, annual general meeting held on 29 November 2019. The 3 year term of these loans were extended by a further 2 years to 31 December 2024, following approval by shareholders at the Company's 2022 annual general meeting held on 29 November 2022 :

Key management personnel (borrower)	Principal sum (A$)	Interest rate %	Term
Maynard Smith	625,000	Nil	2 years
Prent Kallenberger	625,000	Nil	2 years
William Sack	625,000	Nil	2 years
Nick Filipovic	250,000	Nil	2 years

At the end of the term, each borrower is required to repay the amounts outstanding under the loans. If a borrower does not repay a loan, the Company may demand that a borrower dispose of sufficient loan funded shares to satisfy up to the total amount owing under the loan. The Company's recourse against each borrower for repayment of the loans is limited to the proceeds of the loan funded shares.

(ii) In January 2022, the Company provided unsecured 3 year interest free loans to the executive directors to fund the acquisition of the shares issued as a consequence of the exercise of options, treated as treasury shares for accounting purposes. The interest free loans were approved by shareholders at the Company's 2021, annual general meeting held on 29 November 2021, and granted to key management personnel during the financial year. Loans outstanding as of 30 June 2023 are:

Key management personnel (borrower)	Principal sum (A$)	Interest rate %	Term
Maynard Smith and associates	1,596,000	Nil	3 years
Prent Kallenberger and associates	1,596,000	Nil	3 years
William Sack and associates	1,596,000	Nil	3 years
Nick Filipovic and associates	1,013,600	Nil	3 years

At the end of the term, each borrower is required to repay the amounts outstanding under the loans. If a borrower does not repay a loan, the Company may demand that a borrower dispose of sufficient loan funded shares to satisfy up to the total amount owing under the loan. The Company's recourse against each borrower for repayment of the loans is limited to the proceeds of the loan funded shares.

At the end of the financial year, there were no share-based payment arrangements in existence, except for the share based loan specified above.

Additional Information – key management personnel equity and share option holdings

The interests of each director and other key management personnel (directly and indirectly), in the shares and option of Byron Energy Limited are as follows:

Ordinary Shares

Director/Key management personnel	Balance on 30 June 2022 Number	Granted as compensation Number	Received on exercise of options Number	Net other changes Number	Balance on 30 June 2023 Number
D. G. Battersby	57,300,568	–	–	500,000	**57,800,568**
M. V. Smith	49,047,991	–	–	–	**49,047,991**
P. H. Kallenberger	12,808,762	–	–	–	**12,808,762**
C. J. Sands	24,710,783	–	–	–	**24,710,783**
P. A. Young	27,446,619	–	–	1,777,778	**29,224,397**
W. R. Sack	15,300,001	–	–	–	**15,300,001**
N. Filipovic	7,301,359	–	–	–	**7,301,359**

During the financial year, no shares or share options were granted to directors or other key management personnel of the Company.

Other transactions with key management personnel of the Group

Loans from directors and shareholders

Loans

In March 2019, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with four of the Company's directors for loans from companies controlled by directors or loans from directors for a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in September 2023, however the directors agreed to extend the loan repayment date to March 2025 and interest payments have been made on a quarterly basis. Subsequent to 30 June 2023, the directors and a shareholder agreed to further extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum effective 1 August 2023 with the additional 2% to be capitalised until loan repayment date of 31 December 2025. The individual directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, provided an unsecured loan of A$1,400,000 to the Company and interest paid for the financial year to June 2023 was A$140,000, plus A$11,507 has been accrued as at 30 June 2023;
- Clapsy Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2023 was A$17,500, plus A$1,438 has been accrued as at 30 June 2023;
- Poal Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2023 was A$17,500, plus A$1,438 has been accrued as at 30 June 2023;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to June 2023 was US$100,000, plus US$8,219 has been accrued as at 30 June 2023; and
- Mr Charles Sands, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to 30 June 2023 was US$90,000 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2023.

	Short term employee benefits				Post employment benefits	Share-based payments	
	Salaries & fees US$	Short term cash incentive US$	Other Benefits US$	Service Agreements US$	Super-annuation US$	100% vested share options US$*	Total US$
2023							
Directors							
D. G. Battersby	–	–	–	53,872	–	–	53,872
M. S. Smith	–	–	–	491,944	–	35,007	526,951
P. H. Kallenberger	464,888	–	25,980	–	–	35,007	525,875
C. J. Sands	26,936	–	–	–	–	–	26,936
P. A. Young	26,936	–	–	–	2,828	–	29,764
W. R. Sack	464,888	–	36,955	–	–	35,007	536,850
N. Filipovic	268,333	–	–	–	28,175	14,003	310,511
	1,251,981	–	62,935	545,816	31,003	119,024	2,010,759

* Represents share based payments expense for the extension of interest free loans previously made to executive directors and senior staff and for the conversion of share options to fully paid ordinary shares in 2019.

	Short term employee benefits				Post employment benefits	Share-based payments	
	Salaries & fees US$	Short term cash incentive US$	Other Benefits US$	Service Agreements US$	Super-annuation US$	Exercise of share options** US$	Total US$
2022							
Directors							
D. G. Battersby	–	–	–	58,064	–	–	58,064
M. S. Smith	–	–	–	472,042	–	314,226	786,268
P. H. Kallenberger	413,875	–	32,341	–	–	314,226	760,442
C. J. Sands	29,032	–	–	–	–	–	29,032
P. A. Young	29,032	–	–	–	2,903	–	31,935
W. R. Sack	413,875	–	34,887	–	–	314,226	762,988
N. Filipovic	257,478	–	–	–	25,748	191,356	474,582
	1,143,292	**–**	**67,228**	**530,106**	**28,651**	**1,134,034**	**2,903,311**

** Represents share based payments in respect to loan funded shares issued upon exercise of options in January 2022.

The above salaries and fees, other benefits and service agreement payments are not performance related.

Bonuses

Nil bonuses were granted to executive directors and the key management personnel during the financial year ended 30 June 2023 (2022: US$ nil).

End of Remuneration Report.

This Directors' Report is signed in accordance with a resolution of directors made pursuant to s.298(2) of the *Corporations Act 2001*.

On behalf of the directors

D. G. Battersby
Chairman

29 September 2023

Auditor’s Independence Declaration

Deloitte.

Deloitte Touche Tohmatsu
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29 Septemer 2023

Board of Directors
Byron Energy Limited
Level 4, 480 Collins street
Melbourne VIC 3000

Dear Board Members

Auditor’s Independence Declaration to Byron Energy Limited

In accordance with section 307C of the *Corporations Act 2001*, I am pleased to provide the following declaration of independence to the Directors of Byron Energy Limited.

As lead audit partner for the audit of the financial report of Byron Energy Limited for the year ended 30 June 2023, I declare that to the best of my knowledge and belief, there have been no contraventions of:

- the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and
- any applicable code of professional conduct in relation to the audit.

Yours faithfully

Deloitte Touche Tohmatsu
DELOITTE TOUCHE TOHMATSU

Jane Fisher
Partner
Chartered Accountants

Liability limited by a scheme approved under Professional Standards Legislation
Member of Deloitte Asia Pacific Limited and the Deloitte Network.

Consolidated Statement of Profit or Loss and other Comprehensive Income

For the Financial Year Ended 30 June 2023

		Consolidated	
	Note	2023 US$	2022 US$
Continuing operations			
Oil sales		**54,438,879**	49,576,893
Gas sales		**10,499,406**	15,150,610
Total revenue from sales of oil and gas		**64,938,285**	64,727,503
Royalty expense		**(11,918,919)**	(11,584,092)
Cost of sales	2	**(20,565,589)**	(19,105,413)
Gross profit		**32,453,777**	34,037,998
Recoupment of operator overheads		**370,181**	293,271
Realised loss on forward commodity price contracts		**–**	(481,461)
Corporate and administration costs		**(3,247,960)**	(2,920,851)
Impairment expense	8(a)	**(3,123,647)**	(3,082,807)
Share based payments		**(133,026)**	(1,599,464)
Depreciation of property, plant & equipment		**(460,239)**	(484,697)
Other expenses		**(1,677,749)**	(1,412,030)
Finance income	3	**87,056**	132,815
Finance expense	3	**(1,552,666)**	(2,267,466)
Profit before tax		**22,715,727**	22,215,308
Income tax expense	4	**–**	–
Profit for the year from continuing operations		**22,715,727**	22,215,308
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Cumulative loss on oil price cashflow hedges reclassified to profit & loss		**–**	428,596
Exchange differences on translating the parent entity group	16	**7,360**	11,600
Total comprehensive income for the year		**22,723,087**	22,655,504
Earnings per share			
Basic (cents per share)	5	**2.184**	2.135
Diluted (cents per share)	5	**2.101**	2.096

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

At 30 June 2023

	Note	Consolidated 2023 US$	2022 US$
Assets			
Current assets			
Cash and cash equivalents	23(b)	**4,223,877**	14,087,032
Trade and other receivables	6	**4,364,488**	7,492,552
Other	7	**2,771,345**	2,257,545
Total current assets		**11,359,710**	23,837,129
Non-current assets			
Exploration and evaluation assets	8(a)	**1,519,465**	2,545,486
Oil and gas properties	8(b)	**127,975,635**	121,751,736
Right-of-use assets	9	**550,400**	1,002,348
Trade and other receivables	6	**15,021**	102,335
Property, plant and equipment	11	**14,910**	23,427
Other	7	**3,054,542**	1,783,007
Total non-current assets		**133,129,973**	127,208,339
Total assets		**144,489,683**	151,045,468
Liabilities			
Current liabilities			
Trade and other payables	12	**3,645,349**	16,797,661
Provisions	13	**190,878**	182,950
Lease liabilities	10	**505,904**	568,183
Borrowings	14	**2,194,155**	20,978,748
Total current liabilities		**6,536,286**	38,527,542
Non-current liabilities			
Trade and other payables	12	**325,000**	325,000
Provisions	13	**5,650,756**	5,957,795
Lease liabilities	10	**217,636**	723,539
Borrowings	14	**3,392,300**	–
Total non-current liabilities		**9,585,692**	7,006,334
Total liabilities		**16,121,978**	45,533,876
Net assets		**128,367,705**	105,511,592
Equity			
Issued capital	15	**139,117,070**	139,117,070
Foreign currency translation reserve	16	**(27,758)**	(35,118)
Share option reserve	16	**8,037,559**	7,904,533
Accumulated losses		**(18,759,166)**	(41,474,893)
Total equity		**128,367,705**	105,511,592

The accompanying notes form part of these financial statements.

Consolidated Statement of Changes in Equity

For the Financial Year Ended 30 June 2023

Consolidated entity	Ordinary share capital US$	Share option reserve US$	Other reserves US$	Accumulated losses US$	Total US$
Balance at 1 July 2021	139,093,311	6,305,069	(475,314)	(63,690,201)	81,232,865
Profit for the year	–	–	–	22,215,308	22,215,308
Change in value of financially settled swaps written down to fair value	–	–	428,596	–	428,596
Exchange differences arising on translation of the parent entity group	–	–	11,600	–	11,600
Total comprehensive profit for the year	–	–	440,196	22,215,308	22,655,504
Issue of shares on exercise of options	23,759	–	–	–	23,759
Recognition of share-based payments	–	1,599,464	–	–	1,599,464
Balance at 30 June 2022	139,117,070	7,904,533	(35,118)	(41,474,893)	105,511,592
Balance at 1 July 2022	**139,117,070**	**7,904,533**	**(35,118)**	**(41,474,893)**	**105,511,592**
Profit for the year	**–**	**–**	**–**	**22,715,727**	**22,715,727**
Exchange differences arising on translation of the parent entity group	**–**	**–**	**7,360**	**–**	**7,360**
Total comprehensive profit for the year	**–**	**–**	**7,360**	**22,715,727**	**22,723,087**
Recognition of share-based payments	**–**	**133,026**	**–**	**–**	**133,026**
Balance at 30 June 2023	**139,117,070**	**8,037,559**	**(27,758)**	**(18,759,166)**	**128,367,705**

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

For the Financial Year Ended 30 June 2023

	Note	Consolidated 2023 US$	2022 US$
Cash flows from operating activities			
Receipts from customers		**69,030,799**	60,685,271
Payments to suppliers and employees		**(27,196,788)**	(21,687,710)
Interest paid		**(1,279,950)**	(2,435,083)
Interest received		**9,543**	49,932
Net cash flows from operating activities	23(a)	**40,563,604**	36,612,410
Cash flows from investing activities			
Payments for development of oil and gas properties		**(31,312,757)**	(7,501,567)
Payments for exploration and evaluation assets		**(2,713,579)**	(18,042,292)
Net cash flows used in investing activities		**(34,026,336)**	(25,543,859)
Cash flows from financing activities			
Proceeds from exercise of options		**–**	23,759
Repayment of lease liabilities		**(566,593)**	(561,621)
Repayment of borrowings (including prepaid revenue repayments)		**(15,830,114)**	(15,575,242)
Proceeds from borrowings (including prepaid revenue receipts)		**–**	15,000,000
Net cash flows used in financing activities		**(16,396,707)**	(1,113,104))
Net (decrease)/increase in cash and cash equivalents held		**(9,859,439)**	9,955,447
Cash and cash equivalents at the beginning of the year		**14,087,032**	4,143,411
Effect of exchange rate changes on the balance of cash held in foreign currencies		**(3,716)**	(11,826)
Cash and cash equivalents at the end of the year	23(b)	**4,223,877**	14,087,032

The accompanying notes form part of these financial statements.

Notes to the Financial Statements

For the Financial Year Ended 30 June 2023

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Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2023

1. Summary of significant accounting policies

Statement of compliance

These financial statements are general purpose financial statements which have been prepared in accordance with the *Corporations Act 2001*, Accounting Standards and Interpretations, and comply with other requirements of the law.

The financial statements comprise the consolidated financial statements of the Group. For the purposes of preparing the consolidated financial statements, the Company is a for-profit entity.

Accounting Standards include Australian Accounting Standards. Compliance with Australian Accounting Standards ensures that the financial statements and notes of the Company and Group comply with International Financial Reporting Standards ('IFRS').

The financial statements were authorised for issue by the directors on 29 September 2023.

The following significant policies have been adopted in the preparation and presentation of the financial statements:

Basis of preparation

The financial report has been prepared on the basis of historical cost. Historical cost is based on the fair values of the consideration given in exchange for goods and services. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. All amounts are presented in United States of America dollars, unless otherwise noted.

Critical accounting judgments and key sources of estimation uncertainty

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expense. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised and in any future periods effected.

In particular, information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amount recognised in the financial statements are described in notes 1 (c) Oil and gas properties (amortisation based upon estimates of proved and probable reserves), 1 (d) Impairment and on the amounts recognised in the financial statements are described in Note 8 Exploration and evaluation assets/Oil and gas properties.

Another area of estimation uncertainty relates to the future cost to remove oil and gas production facilities, abandonment of wells and restoring the affected areas. The provision for future restoration is the best estimate of the present value of the expenditure required to settle the obligation at the reporting date, based on current legal requirements and technology.

Please see notes 1 (m) Provisions (site restoration) and note 13.

Adoption of new and revised Accounting Standards

The Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board ("AASB") and none are relevant and/or have a material impact on the Group in the current financial year.

Standards and Interpretations issued not yet effective – IASB and IFRIC Interpretations

At the date of authorisation of the financial statements, the following AASB Standards and IFRIC Interpretations were in issue but not yet effective:

Standard/Interpretation	Effective for annual reporting periods beginning on or after	Expected to be initially applied in the financial year ending
AASB 2022-6 Amendment to Australian Accounting Standards – Non-current Liabilities with Covenants	1 January 2023	30 June 2024
AASB 2022-7 Editorial corrections to Australian Accounting Standards and Repeal of Superseded and Redundant Standards	1 January 2023	30 June 2024
AASB 2020-1 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current and AASB 2020-6 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current – deferral of effective date	1 January 2024	30 June 2025
AASB 2021-2 Amendments to Australian Accounting Standards – Disclosure of Accounting Policies and Definition of Accounting Estimates	1 January 2023	30 June 2024
AASB 2021-5 Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction	1 January 2023	30 June 2024
AASB 2022-5 Amendments to Australian Accounting Standards – Lease Liability in a sale and leaseback	1 January 2024	30 June 2025

The directors do not expect that the adoption of the Standards listed above will have a material impact on the financial statements of the Group in future periods.

The following significant accounting policies have been adopted in the preparation and presentation of the financial report:

(a) Basis of consolidation

Subsidiaries

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (referred to as 'the consolidated entity' or 'the Group' in these financial statements). Control is achieved where the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated income statement from the effective date of acquisition or up to the effective date of disposal, as appropriate. Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the consolidated entity.

Joint operating arrangements

Joint operating arrangements are those legal entities over whose activities the consolidated entity has joint control, established by contractual agreement. The interest of the consolidated entity in unincorporated joint operating arrangements are brought to account by recognising in its financial statements, its respective share of the assets it controls, the liabilities and the expenses it incurs and its share of income that it earns from the sale of goods or services by the joint operating arrangements.

Transactions eliminated on consolidation

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

1. Summary of significant accounting policies continued

(b) Exploration and evaluation expenditure

Exploration and evaluation costs, including the costs of acquiring leases, are intangible assets capitalised as exploration and evaluation assets on an area of interest basis. Costs incurred before the consolidated entity has obtained the legal rights to explore an area are recognised in the income statement.

Exploration and evaluation assets are only recognised if the rights of the area of interest are current and either:

(i) the expenditures are expected to be recouped through successful development and exploitation of the area of interest; or alternatively, by its sale; or (ii) activities in the area of interest have not, at the reporting date, reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the area of interest are continuing.

Exploration and evaluation assets are initially measured at cost and include acquisition of rights to explore, lease rental payments, seismic and other expenditure to provide legal tenure of the area of interest. When an area of interest is abandoned or the directors decide that it is not commercial, any capitalised costs in respect of that area are written off in the financial period the decision is made.

Exploration and evaluation assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

Farm in and farm outs:

In the case of farmouts, the Group does not record any expenditure made by the farminee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farminee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for as a gain on disposal.

In the case of farmins, Byron accounts for its expenditures under a farm-in arrangement in the same way as directly incurred exploration and evaluation expenditure.

For the purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units to which the exploration activity relates. The cash generating unit shall not be larger than the area of interest.

Once the technical feasibility and commercial viability of the extraction of oil and gas reserves relating to a prospect are demonstrable and development is proceeding, exploration and evaluation assets attributable to that prospect are first tested for impairment and then reclassified to oil and gas properties.

All other exploration and evaluation costs are expensed as incurred.

(c) Oil and gas properties

The cost of oil and gas producing assets include acquisition and capitalised development costs that are directly attributable to the accessing and production of the proved and probable oil and gas reserves.

In addition, costs include:

(i) the initial estimate at the time of installation or acquisition and during the period of use, when relevant of the costs of dismantling and removing the items and restoring the site on which they are located, and

(ii) changes in the measurement of existing liabilities recognised for these costs resulting from changes in the timing or outflow of resources required to settle the obligation or from changes in the discount rate.

Amortisation

When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a units of production of basis over the remaining proved and probable recoverable reserves ("2P"). The remaining 2P reserves are measured by external independent petroleum engineers.

Changes in factors that affect amortisation calculations do not give rise to prior financial period adjustments and are dealt with on a prospective basis.

(d) Impairment

The carrying amounts of the company's and the consolidated entity's non-financial assets, except exploration and evaluation expenditure, are reviewed each balance date or when there is an indication of an impairment loss, to determine whether they are in excess of their recoverable amount. An impairment loss is recognised whenever the carrying amount of an asset or its cash generating unit exceeds its recoverable amount.

Calculation of the recoverable amount

The recoverable amount of an asset is the greater of its fair value less cost to sell and value in use. In assessing the fair value less cost to sell, the estimated future cash flows are discounted to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in profit or loss. Refer to note 8 for further details.

Reversals of impairment

Impairment losses are reversed when there has been a change in the estimates used to determine recoverable amounts.

An impairment loss is reversed only to the extent that the asset's carrying value does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment loss had been recognised.

(e) Foreign currency

Functional and presentation currency

Items included in the financial statements of each of the consolidated entity's subsidiaries are measured using the currency of the primary economic environment in which the subsidiaries operate ("the functional currency"). The functional currency of the Company is Australian dollars (A$) and the functional currency of the Company's overseas subsidiaries is United States dollars (US$).

The financial statements are presented in United States dollars. The consolidated entity believes the US dollar is the best measure of performance for the Group because oil and gas, the consolidated entity's dominant sources of revenue are priced in US$ and the consolidated entity's main operations are based in the USA with costs incurred in US$.

Prior to consolidation, the results and financial position of each entity within the consolidated entity are translated from the functional currency into the consolidated entity's presentation currency as follows:

- asset and liabilities of the non US$ denominated balance sheet are translated at the closing rate at the date of that
- balance sheet;
- income and expenses for the non US$ denominated income statement is translated at average exchange rates
- (unless this is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction
- dates, in which case the income and expenses are translated at the dates of the transactions);
- components of equity are translated at the historical rates; and
- all resulting exchange differences are recognised as a separate component of equity.

Foreign currency transactions and balances

Non-monetary asset and liabilities that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

Foreign exchange gains and losses arising from a monetary item receivable from or payable to a foreign operation, the settlement of which is neither nor likely in the foreseeable future, are considered to form part of the net investment in a foreign operation are recognised directly in equity in the foreign currency translation reserve.

Interest bearing loans and borrowings repayable in fixed currency denominations

Interest bearing loans and borrowings are initially measured at fair value, net of transaction costs. As some of the loans from shareholders are legally repayable in non-functional or non United States currency denominations, any unrealised foreign currency exchange gains and losses emanating from the recognition of the amounts required to settle these future obligations are recognised in the profit and loss.

1. Summary of significant accounting policies continued

(f) Cash and cash equivalents

Cash comprises cash on hand and deposits held at call with financial institutions. Cash equivalents are short-term, highly liquid investments that are readily convertible to known amounts of cash, which are subject to an insignificant risk of changes in value.

(g) Share based payments

Equity settled share based payments with directors, employees and others providing similar services are measured at the fair value of the equity instrument at the grant date. Fair value is measured by use of an appropriate model. A share based payment expense is recognised in profit and loss with a corresponding increase in equity at grant date where the share based payment arrangements vest immediately. Loans may be provided by the Company to fund the acquisition of the shares issued as a consequence of the exercise of options. These loan funded shares are measured at the fair value of the equity instrument at the grant date and are treated as treasury shares for accounting purposes as they are backed by non recourse loans, which will not be repaid until the shares are sold, and are in a trading lock. These shares have the same rights as all other fully paid ordinary shares issued by the Company, except they are placed in a trading lock. For the purposes of calculating the diluted earnings per share, the treasury shares are included in the weighted average number of shares.

(h) Revenue recognition

Oil and gas revenue

Revenue from the sale of crude oil, natural gas, condensate and NGLs is recorded based on quantities of production sold to purchasers under short-term contracts at market prices when delivery to the customers has occurred, title has transferred, prices are fixed and determinable and collections is reasonably assured. Revenue from the sale of oil, NGL's and natural gas is recognised when performance obligations under the terms of the respective contracts are satisfied; this generally occurs with delivery of oil, NGL's and natural gas to the customer. Each unit of product represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance is not required.

Interest income

Interest income is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

(i) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognised in the profit or loss except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantially enacted at the balance sheet date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognised using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised for the following temporary differences: the initial recognition of goodwill, the initial recognition of assets or liabilities in a transaction that is not a business combination and that affect neither accounting nor taxable profit/loss, and differences relating to investments in subsidiaries to the extent that they will not reverse in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the balance sheet date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the asset can be utilised. Deferred tax assets are reviewed at each balance sheet date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

(j) Financial assets

Financial assets and financial liabilities are recognised when the Company becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss) are added to, or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognised immediately in profit or loss.

Financial assets

Financial assets are measured subsequently in their entirety at either amortised cost or fair value, depending on the classification of the financial assets (this note is also applicable note 1(r) Derivative financial instruments – cash flow hedges).

Classification of Financial assets

Debt instruments that meet the following conditions are measured subsequently at amortised cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Debt instruments that meet the following conditions are measured subsequently at fair value through other comprehensive income (FVTOCI):

- The financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

By default, all other financial assets are measured subsequently at fair value through profit or loss (FVTPL).

Despite the foregoing, the Company may make the following irrevocable election/designation at initial recognition of a financial asset:

- The Company may irrevocably elect to present subsequent changes in fair value of an equity investment in other comprehensive income if certain criteria are met; and
- The Company may irrevocably designate a debt investment that meets the amortised cost or FVTOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch.

Initial measurement of financial assets

Financial assets are classified according to their business model and the characteristics of their contractual cash flows. Except for those trade receivables that do not contain a significant financing component and are measured at the transaction price in accordance with AASB 15, all financial assets are initially measured at fair value adjusted for transaction costs.

Subsequent measurement of financial assets

For the purpose of subsequent measurement, financial assets, other than those designated and effective as hedging instruments, are classified into the following four categories:

- Financial assets at amortised cost;
- Debt instruments at fair value through other comprehensive income (FVTOCI);
- Equity instruments at FVTOCI; and
- Financial assets at FVTPL

(i) Amortised cost and effective interest method

The effective interest method is a method of calculating the amortised cost of a debt instrument and of allocating interest income over the relevant period.

(ii) Debt instruments at fair value through other comprehensive income (Debt FVTOCI)

Debt FVTOCI initially measured at fair value plus transaction costs. Subsequently, changes in the carrying amount of these as a result of foreign exchange gains and losses, impairment gains or losses, and interest income calculated using the effective interest method are recognised in profit or loss.

1. Summary of significant accounting policies continued

(iii) Equity instruments at fair value through other comprehensive income (Equity FVTOCI)

Investments in equity instruments at FVTOCI are initially measured at fair value plus transaction costs. Subsequently, they are measured at fair value with gains and losses arising from changes in fair value recognised in other comprehensive income and accumulated in the investments revaluation reserve. The cumulative gain or loss is not to be reclassified to profit or loss on disposal of the equity investments, instead, it is transferred to retained earnings.

(iv) Financial assets at fair value through profit or loss (FVTPL)

Financial assets at FVTPL are measured at fair value at the end of each reporting period, with any fair value gains or losses recognised in profit or loss to the extent they are not part of a designated hedging relationship. The net gain or loss recognised in profit or loss includes any dividend or interest earned on the financial asset and is included in the "Net gain/(loss) arising on financial assets measured at FVTPL" line.

Impairment of financial assets

The Company recognises a loss allowance for expected credit losses on investments in debt instruments that are measured at amortised cost or at FVTOCI, lease receivables, trade receivables and contract assets, as well as on financial guarantee contracts. The amount of expected credit losses is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

Trade and other receivables and contract assets

The Company makes use of a simplified approach in accounting for trade and other receivables as well as contract assets and records the loss allowance at the amount equal to the expected lifetime credit losses. In using this practical expedient, the Company uses its historical experience, external indicators and forward-looking information to calculate the expected credit losses using a provision matrix.

(k) Employee benefits

A liability is recognised for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required and they are capable of being measured reliably.

Liabilities recognised in respect of employee benefits expected to be settled within 12 months, are measured at their nominal values using the remuneration rate expected to apply at the time of settlement.

Liabilities recognised in respect of employee benefits which are not expected to be settled within 12 months are measured as the present value of the estimated future cash outflows to be made by the consolidated entity in respect of services provided by employees up to reporting date.

Defined contribution plans

Contributions to defined contribution superannuation plans are expensed when employees have rendered service entitling them to the contributions.

(l) Property, plant and equipment

Buildings held for use in the production or supply of goods or services, or for administrative purposes, are carried in the statement of financial position at cost, less any subsequent accumulated depreciation and subsequent accumulated impairment losses.

Plant and equipment are stated at cost less accumulated depreciation and impairment. Construction in progress is stated at cost. Cost includes expenditure that is directly attributable to the acquisition or construction of the item. In the event that settlement of all or part of the purchase consideration is deferred, cost is determined by discounting the amounts payable in the future to their present value as at the date of acquisition.

Depreciation is provided on property, plant and equipment, including freehold buildings but excluding land. Depreciation is calculated on a straight-line basis so as to write off the net cost or other revalued amount of each asset over its expected useful life to its estimated residual value. The estimated useful lives, residual values and depreciation method are reviewed at the end of each annual reporting period, with the effect of any changes recognised on a prospective basis.

The gain or loss arising on disposal or retirement of an item of property, plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in profit or loss.

The following useful lives are used in the calculation of depreciation:

Buildings	40 years
Plant and equipment	4 to 10 years

(m) Provisions

Provisions are recognised when the consolidated entity has a present obligation (legal or constructive) as a result of a past event, it is probable that the consolidated entity will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cashflows estimated to settle the present obligation, its carrying amount is the present value of those cashflows.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognised as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

Site restoration and rehabilitation of oil and gas properties

Provisions made for environmental rehabilitation are recognised where there is a present obligation as a result of exploration, development or production activities having been undertaken and it is probable that an outflow of economic benefits will be required to settle the obligation, and the amount of the provision can be measured reliably. The estimated future obligations include the cost of removing the facilities, abandoning the well(s) and restoring the affected areas. The provision for future restoration is the best estimate of the present value of the expenditure required to settle the obligation at the reporting date, based on current legal requirements and technology. Future restoration costs are reviewed annually; and any changes are reflected in the present value of the restoration provision at the end of the reporting period. The amount of the provision for future restoration costs relating to exploration and producing activities is capitalised as a cost of these activities. The provisions are determined by discounting the expected future cashflows at a pre tax rate that reflects the time value of money. The unwinding of discounting on the provision is recognised as a finance cost rather than being capitalised into the cost of the related asset.

(n) Financial liabilities

Financial liabilities

Financial liabilities, including borrowings and trade and other payables, are initially measured at fair value, net of transaction costs (this note is also applicable note 1(r) Derivative financial instruments – cash flow hedges). All financial liabilities are subsequently measured at amortised cost using the effective interest method, with interest expense recognised on an effective yield basis.

The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments through the expected life of the financial liability, or (where appropriate) a shorter period, to the net carrying amount on initial recognition.

Borrowing, finance and interest costs

Borrowing, finance and interest costs comprise interest payable on borrowings calculated using the effective interest rate method, loans transactions costs, lease finance charges, amortisation of discounts or premiums related to the borrowings and the unwinding of discounts on the rehabilitation provisions.

Derecognition of financial liabilities

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

(o) Issued capital

Issued and paid up capital is recognised at the fair value of the consideration received by the Company.

Transaction costs on the issue of equity instruments

Transaction costs arising on the issue of equity instruments are recognised directly in equity as a reduction of the proceeds of the equity instrument to which the costs relate. Transaction costs are costs that are incurred directly in connection with the issue of those equity instruments and which would not have been incurred had those instruments not been issued.

1. Summary of significant accounting policies continued

(p) Reserves

Foreign Currency Translation Reserve

Foreign currency exchange differences relating to the translation of Australian dollars, being the functional currency of the parent entity group into the presentational currency of US dollars for the consolidated entity are brought to account by entries made directly to the foreign currency translation reserve.

Share Option Reserve

The share option reserve arises on the grant of share options to directors, staff, consultants and other service providers to the Group, if the share options vest immediately. Where share options vest over time the share option reserve rise rises over the vesting period. Amounts are transferred out of the reserve and into issued capital when the options are exercised. Further information about share based payments is made in note 1(g).

Cashflow hedging Reserve

The cashflow hedging reserve arises when the effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve. Further information about cashflow hedges is made in note 1(r) Derivative financial instruments – cash flow hedge.

(q) Goods and services tax

Revenues, expenses and assets are recognised net of the amount of goods and services tax ("GST"), except:

(i) where the amount of GST incurred is not recoverable from the taxation authority, it is recognised as part of the cost of acquisition of an asset or as part of an item of expense; or

(ii) for receivables and payables which are recognised inclusive of GST.

The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables.

Cash flows are included in the cash flow statement on a gross basis. The GST component of cash flows arising from investing and financing activities which is recoverable from, or payable to, the taxation authority is classified as operating cash flows.

(r) Derivative financial instruments

From time to time, the Group may enter into a variety of derivative financial instruments to manage its exposure to crude oil price risks, including cash flow hedges.

Cash flow hedges

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge.

Amounts previously recognised in other comprehensive income and accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss, in the same line as the recognised hedged item.

However, when the hedged forecast transaction results in the recognition of a non-financial asset or a non-financial liability, the gains and losses previously recognised in other comprehensive income and accumulated in equity are removed from equity and included in the initial measurement of the cost of the non-financial asset or non-financial liability. This transfer does not affect other comprehensive income. Furthermore, if the Group expects that some or all of the loss accumulated in the cash flow hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in cash flow hedge reserve at that time remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in the cash flow hedge reserve is reclassified immediately to profit or loss.

(s) Leases

The Group as lessee

The Group assesses whether a contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets (such as tablets and personal computers, small items of office furniture and telephones). For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate the Group uses for its incremental borrowing.

Lease payments included in the measurement of the lease liability comprise:

(i) fixed lease payments (including in-substance fixed payments), less any lease incentives receivable; and

(ii) variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date.

The lease liability is presented as a separate line in the consolidated statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method) and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less any lease incentives received and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The right-of-use assets are presented as a separate line in the consolidated statement of financial position.

The Group applies AASB 136 to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'Property, Plant and Equipment' impairment policy.

Variable rents that do not depend on an index or rate are not included in the measurement the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line "Corporate and administration costs" in profit or loss.

As a practical expedient, AASB 116 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. The Group has not used this practical expedient. For a contract that contain a lease component and one or more additional lease or non-lease components, the Group allocates the consideration in the contract to each lease component on the basis of the relative stand-alone price of the lease component and the aggregate stand-alone price of the non-lease components.

(t) Comparative figures

Where required by Accounting Standards, comparative figures have been adjusted to conform to changes in presentation for the current period.

2. Profit for the year

	Consolidated	
	2023 US$	**2022 US$**
Profit for the year has been arrived at after charging the following items of expense		
Cost of sales		
Lease operating costs	**8,497,008**	6,690,581
Gas transportation costs	**625,674**	836,437
Amortisation of oil and gas properties	**11,442,907**	11,578,395
	20,565,589	19,105,413
Professional and consulting costs	**1,054,572**	927,343
Insurance	**198,885**	193,236
Office lease rental expense including outgoings (short term leases)	**178,515**	132,877
Employee benefits expense		
Salaries and wages	**2,473,719**	2,155,288
Share based payments (loans made to salaried executive directors and salaried staff to finance the conversion of share options to fully paid ordinary shares and share options issued to salaried staff)	**88,217**	1,070,720
Defined contribution superannuation expense	**39,739**	36,315
	2,601,675	3,262,323

3. Financial income and expenses

	Consolidated	
	2023 US$	**2022 US$**
Financial Income		
Interest income	**32,666**	725
Foreign exchange gain on A$ denominated loans	**54,390**	132,090
	87,056	132,815
Financial Expense		
Interest expense non related parties	**940,228**	1,664,511
Lease finance costs	**85,724**	130,542
Unwinding of discount on rehabilitation of oil and gas properties	**182,304**	116,979
Interest expense paid or accrued on loans from related parties	**344,410**	355,434
	1,552,666	2,267,466

4. Income tax

	Consolidated	
	2023 US$	**2022 US$**
Income tax recognised in profit and loss	**–**	–
The income tax expense for the year can be reconciled to the accounting profit as follows:		
Profit before tax from continuing operations	**22,715,727**	22,215,308
Income tax expense calculated at 30.0% (30.0% 2022)	**6,814,718**	6,664,592
Effect of expenses that are not deductible in determining taxable profit	**41,090**	479,839
Effect of different tax rates of subsidiaries operating in other jurisdictions	**(241,303)**	(250,059)
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	**(6,614,505)**	(6,894,372)
Income tax expense/(benefit) on continuing operations	**–**	–
Deferred tax assets not recognised		
Deferred tax assets not recognised comprises temporary differences and tax losses attributable to:		
Australian tax losses	**5,083,240**	4,886,128
USA tax losses	**32,704,755**	35,973,460
Temporary differences	**(24,391,093)**	(28,960,359)
Total deferred tax assets not recognised	**13,396,902**	11,899,229

The potential deferred tax asset will only be recognised if:

(i) the consolidated entity derives future assessable income of a nature and amount sufficient to enable the benefits to be realised, in the jurisdiction in which the losses were incurred;

(ii) the consolidated entity continues to comply with conditions for tax deductibility imposed by law; and

(iii) no changes in tax legislation adversely affect the ability of the consolidated entity to realise the tax benefits.

Australian income tax losses have an infinite life and USA tax losses incurred in tax years beginning before 2018 have a 20 year carry forward period and tax losses incurred after 2018 have an infinite life, but utilisation is subject to 80% of taxable income on an annual basis.

Byron Energy Limited and its 100% owned Australian subsidiary, Byron Energy (Australia) Pty Ltd formed a tax consolidated group effective from 1 July 2013.

5. Earnings per share

The following reflects the profit and share data used in calculating basic and diluted earnings per share:

	Consolidated	
	2023 US$	**2022 US$**
Net profit for the year	**22,715,727**	22,215,308
Basic profit per share (cents per share)	**2.184**	2.135
Diluted profit per share (cents per share)	**2.101**	2.096
Weighted average number of ordinary shares	**1,040,295,102**	1,040,295,102
Treasury shares	**41,100,000**	19,592,877
Shares deemed to be issued for no consideration in respect of share options	**–**	–
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	**1,081,395,102**	1,059,887,979
Anti-dilutive options on issue not used in the dilutive earnings per share calculation	**–**	–

6. Trade and other receivables

	Consolidated	
	2023 US$	**2022 US$**
Current		
Oil and gas sales receivables	**3,939,751**	7,337,734
Joint operating arrangements receivables	**374,545**	129,491
Interest receivable	**20,398**	424
GST receivable/other receivables	**29,794**	24,903
	4,364,488	7,492,552
Non-Current		
Joint operating arrangements receivables	**15,021**	102,335

Current trade and other receivables are non-interest bearing and are generally settled within 45 days.

7. Other assets

	Consolidated	
	2023 US$	**2022 US$**
Current		
Prepayments	**2,765,564**	2,251,538
Security deposits	**5,781**	6,007
	2,771,345	2,257,545
Non-Current		
Security deposits	**3,054,542**	1,783,007

8 (a). Exploration and evaluation assets

	Consolidated	
	2023 US$	**2022 US$**
Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**1,519,465**	2,545,486
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**2,545,486**	5,150,621
Additions at cost	**2,097,626**	18,476,352
Transfers of exploration and evaluation assets to oil and gas properties 8 (b)	**–**	(17,998,680)
Impairment expense	**(3,123,647)**	(3,082,807)
Carrying amount at the end of the financial year	**1,519,465**	2,545,486

Ultimate recovery of deferred exploration and evaluation costs is dependent upon success in exploration and evaluation or the full or partial sale (including farm-out) of the exploration interests.

For the year ended 30 June 2023, impairment charges were US$3,123,647 due to (i) relinquishment of the Main Pass 293,305, 306 leases and (ii) relinquishment of the SM70 and SM60 leases.

8 (b). Oil and gas properties

	Consolidated	
	2023 US$	**2022 US$**
Costs carried forward in respect of areas in the oil and gas properties:	**127,975,635**	121,751,736
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**121,751,736**	95,433,081
Additions at cost	**18,170,138**	21,253,667
Additions/(subtractions) for site restoration	**(503,332)**	(1,355,297)
Transfers from exploration and evaluation assets 8 (a)	**–**	17,998,680
Amortisation of oil and gas properties included in cost of sales	**(11,442,907)**	(11,578,395)
Carrying amount at the end of the financial year	**127,975,635**	121,751,736

8 (b). Oil and gas properties continued

The carrying amounts of oil and gas properties comprises three separate cash generating units ("CGU's), SM71 F platform and related wells ("SM71 F"), SM58 G platform and related wells ('SM 58 G") and SM69 E platform and related well (SM 69 E). Each of the platforms is considered to be the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The balance of carrying values by CGU at the end of the financial year is shown below:

	Consolidated	
	2023 US$	**2022 US$**
SM71 F	**23,325,506**	24,460,075
SM58 G	**100,841,082**	93,692,535
SM69 E	**3,809,047**	3,599,126
Carrying amount at the end of the financial year	**127,975,635**	121,751,736

Recoverable amount

At year end, the Company's oil and gas properties were assessed for impairment indicators in accordance with AASB 136. Following this assessment, the recoverable amount was found to exceed the carrying amount of the assets and no impairment was required or recognised on the oil and gas properties during the 30 June 2023 financial year.

The estimated recoverable amount of all cash generating units in the development or production phase is determined by discounting the estimated future cash flows to their present value using a post-tax discount rate that reflects current market assessments of the time value money and the risks specific to the assets. The consolidated entity utilises future cash flows as estimated by independent petroleum engineers for this assessment. The key assumptions used include: (i) estimated future production based on proved and probable reserves (2P reserves) over the economic life of each field of approximately 20 years, although most of the 2P production is estimated to be produced within the next ten years, (ii) hydrocarbon prices that the consolidated entity estimates to be reasonable, taking into account historical prices, current prices, and prices used in making its exploration and development decisions, and (iii) future operating and development costs as estimated by the Company and reviewed for reasonableness by the independent petroleum engineers. The estimated recoverable amount of Byron's oil and gas properties is sensitive to a change in estimated recoverable reserves, oil and gas prices, discount rates and cost estimates.

Oil prices used in the Collarini report represent July 2023 actual price then August 9, NYMEX West Texas Intermediate (WTI) Strip prices starting on August 1, 2023, of US$83.47 per barrel. Beginning January 1, 2024, the Reuters Poll consensus pricing was used with a starting price of US$79.16 per barrel and with a final price of US$66.69 per barrel on January 1, 2027, then held constant thereafter. Gas prices used in this report represent a Henry Hub base August 9, NYMEX Strip prices starting on July 1, 2023, of US$2.959 per MMBtu. Beginning January 1, 2024, the Reuters Poll consensus pricing was used with a starting price of US$3.670 per MMBtu, increasing to US$4.170 per MMBtu on January 2025 then declining to US$3.670 per MMBtu on January 1, 2026, and held constant thereafter. These prices were then adjusted to account for transportation cost, basis difference, Light Louisiana Sweet (LLS) vs WTI oil gravity. It is assumed that the products are sold on the spot market with delivery at the sales point on the production facilities. Hence the Reference Point as defined in paragraph 3.2.1 of the Petroleum Resources Management System is at the sales point on the production facilities.

9. Right-of-use assets

	Consolidated	
	2023 US$	**2022 US$**
Office lease		
Opening balance	**297,760**	485,819
Charge for the year	**(188,059)**	(188,059)
Carrying amount at the end of the financial period	**109,701**	297,760
Compressor lease		
Opening balance	**704,588**	968,477
Charge for the year	**(263,889)**	(263,889)
Carrying amount at the end of the financial period	**440,699**	704,588
Total Right-of-use assets	**550,400**	1,002,348
Amounts recognised in profit and loss		
Depreciation expense on right-of-use assets	**451,948**	451,948
Interest expense on lease liabilities	**85,724**	130,542
Expense relating to short-term leases including outgoings	**178,515**	132,877

10. Lease liabilities

	Consolidated	
	2023 US$	**2022 US$**
Not later than one year	**555,810**	669,793
Later than one year and not later than 5 years	**227,268**	783,078
Minimum lease payments	**783,078**	1,452,871
Less: Future finance charges	**(59,538)**	(161,149)
Provided for in the financial statements	**723,540**	1,291,722
Representing lease liabilities:		
Current	**505,904**	568,183
Non-current	**217,636**	723,539
	723,540	1,291,722

The Group does not face a significant liquidity risk with regard to its lease liabilities. Lease liabilities are monitored within the Group's treasury function.

11. Property, plant and equipment

	Consolidated	
	2023 US$	**2022 US$**
Buildings at cost	**9,685**	10,064
Accumulated depreciation	**(4,130)**	(4,040)
	5,555	6,024
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**6,024**	6,848
Charge for the year	**(246)**	(265)
Foreign currency translation movements	**(223)**	(559)
Carrying amount at the end of the financial year	**5,555**	6,024
Plant and equipment at cost	**131,569**	132,288
Accumulated depreciation	**(122,214)**	(114,885)
	9,355	17,403
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**17,403**	24,624
Charge for the year	**(8,045)**	(7,209)
Foreign currency translation movements	**(3)**	(12)
Carrying amount at the end of the financial year	**9,355**	17,403
Total property, plant and equipment	**14,910**	23,427

12. Trade and other payables

	Consolidated	
	2023 US$	**2022 US$**
Current		
Trade payables	**1,769,588**	15,383,015
Oil and gas royalties payable	**674,582**	1,369,350
Joint venture payable	**1,129,224**	–
Accrued interest on loans	**27,962**	27,507
Other payables	**43,993**	17,789
	3,645,349	16,797,661
Non-Current		
Trade payables	**325,000**	325,000
	325,000	325,000

Terms and conditions relating to the above financial instruments:

(i) trade creditors are non-interest bearing and are usually settled on 30 day terms.

(ii) some of the other payables are non-interest bearing and have an average term of 30 days.

13. Provisions

	Consolidated	
	2023 US$	**2022 US$**
Current		
Accumulated employee entitlements	**190,878**	182,950
	190,878	182,950
Non-current		
Accumulated employee entitlements	**115,483**	101,494
Site restoration SM71 wells, pipelines & platform, SM58 E-1 & SM69 E-2 wells, SM69 pipelines & platform, SM58 wells & SM58 pipelines & platform	**5,535,273**	5,856,301
	5,650,756	5,957,795
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**5,856,301**	7,094,619
Additions/(subtractions) to site restoration	**(503,332)**	(1,355,297)
Unwinding of discount on site restoration	**182,304**	116,979
Carrying amount at the end of the financial year	**5,535,273**	5,856,301

Provisions are recognised for the Group's restoration obligations for the SM71 wells & platform, SM58 E-1, SM69 E-2, SM58 G1, G2ST, G3 & G5 wells, SM58 and SM69 pipelines & platforms. The estimation of future costs associated with the abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until quite a few years into the future. Such cost estimates could be subject to revisions in subsequent years due to regulatory requirements, technological advances and other factors that are difficult to predict. Likewise the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The interest rates used to determine the restoration obligations at 30 June 2023 were approximately 3.84% (2022 within the range of 3.09% to 3.12%), and were based on applicable government bond rates with a tenure aligned to the tenure of the liability. The measurement and recognition criteria relating to restoration obligations is described in note 1 (m).

14. Borrowings

	Consolidated	
	2023 US$	**2022 US$**
Current unsecured		
Loans from directors and shareholder*	**–**	3,446,690
Prepaid oil revenues	**–**	11,000,000
Insurance premium financing (interest bearing)**	**2,194,155**	1,701,944
Current secured		
Promissory note – debt liability	**–**	4,830,114
Total current borrowings	**2,194,155**	20,978,748
Non-Current unsecured		
Loans from directors and shareholder*	**3,392,300**	–
Total non-current borrowings	**3,392,300**	–

* The loan facility was fully drawn during the March 2019 quarter, is unsecured and following agreement by the director's and a longstanding shareholder during the financial year, during the year ended 30 June 2023, the repayment date was extended to 31 March 2025 bearing an interest from time of drawdown, at a rate of 10% per annum, payable every quarter. The decrease in the loans for the period is solely due to a weaker Australia dollar relative to the USA dollar. Subsequent to 30 June 2023, the directors agreed to further extend to extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum affective 1 September 2023. With the additional 2% to be capitalised until loan repayment date of 31 December 2025.

** The insurance premium financing bears an average 6.95% fixed interest rate, refer note 28(c).

15. Issued capital

	Consolidated	
	2023 US$	**2022 US$**
(a) Issued and paid up capital	**139,117,070**	139,117,070

Changes to the then Corporations Law abolished the authorised capital and par value concept in relation to share capital from 1 July 1998. Therefore, the Company does not have a limited amount of authorised capital and issued shares do not have a par value.

(b) Movement

	2023		2022	
	Number	**US$**	**Number**	**US$**
Fully paid ordinary shares				
Balance at beginning of the financial year	**1,081,395,102**	**139,117,070**	1,040,295,102	139,093,311
Options converted to fully paid shares	**–**	**–**	41,100,000*	–
Issue of shares on exercise of options.	**–**	**–**	–	23,759
Closing balance at end of financial year	**1,081,395,102**	**139,117,070**	1,081,395,102	139,117,070
Less shares classified as treasury shares				
Balance at beginning of the financial year	**41,100,000***	**–**	–	–
Conversion of options to fully paid shares	**–**	**–**	41,100,000*	–
Closing balance at end of financial year	**41,100,000***	**–**	41,100,000*	–
Closing balance at end of financial year	**1,040,295,102**	**139,117,070**	1,040,295,102	139,117,070

* Fully paid ordinary shares treated as treasury shares for accounting purposes as they are backed by non recourse loans, which will not be repaid until the shares are sold, and are in a trading lock. These shares have the same rights as all other fully paid ordinary shares issued by the Company, except they are placed in a trading lock.

(c) Terms and conditions of contributed equity

Ordinary shares

Ordinary shares have the right to receive dividends as declared and in the event of winding up of the Company, to participate in the proceeds from the sale of all surplus assets in proportion to the number of and amounts paid up on shares held. Ordinary shares entitle their holder to one vote, either in person or by proxy, at a meeting of the Company.

The issued capital of the Company comprises 1,081,395,102 ordinary shares (2022: 1,081,395,102). All the shares are quoted on the ASX, including 41,100,000 fully paid ordinary shares treated as treasury shares for accounting purposes. These shares have the same rights as all other fully paid ordinary shares issued by the Company, except they are placed in a trading lock.

(d) Share options

During the financial year, no share options were converted to fully paid ordinary shares.

At the end of the financial year, there were 2,000,000 (2022: 2,000,000) unissued ordinary shares in respect of which the following options were outstanding:

Expiry date	Number	Securities	Exercise price
31 December 2024	2,000,000	Unlisted options	A$0.16
Total	2,000,000		

No share options were issued during the financial year and no share options expired, unexercised during the financial year.

16. Reserves

	Consolidated	
	2023 US$	**2022 US$**
Foreign currency translation reserve		
Balance at beginning of financial year	**(35,118)**	(46,718)
Currency translation movements for the year	**7,360**	11,600
Balance at end of financial year	**(27,758)**	(35,118)

The reserve arises out of the translation of A$, being the functional currency of the Australian parent entity and its Australian wholly owned subsidiary into the consolidated entity presentation currency of US$.

	2023 US$	**2022 US$**
Share option reserve		
Balance at beginning of financial year	**7,904,533**	6,305,069
Extension of interest free loans previously made to executives, consultants and staff for the conversion of share options to fully paid ordinary shares in 2019*	**133,026**	–
Loans made to executive directors, staff and consultants for the conversion of 41,100,000 share options to fully paid ordinary shares	**–**	1,514,947
2,000,000 options issued to senior staff	**–**	84,517
Balance at end of financial year	**8,037,559**	7,904,533

* In 2019, Byron issued 9,500,000 fully paid ordinary shares following the exercise of 9,500,000 share options via interest free loans made to the relevant option holders. The Company provided unsecured 3 year interest free loans to the option holders to fund the acquisition of the shares issued as a consequence of the exercise of options. The interest free loans were approved by shareholders at the Company's 2019 annual general meeting. The loans were due to expire as at 31 December 2022. At the Company's November 2022 AGM shareholders approved the extension of the loans to 31 December 2024.

17. Employee benefits and superannuation commitments

The consolidated entity contributes in accordance with the Australian Government superannuation guarantee legislation.

18. Auditors' remuneration

	Consolidated	
	2023 US$	**2022 US$**
Amounts received or due and receivable by Deloitte Touche Tohmatsu:		
Audit or review of the financial statements of the Group	**75,620**	73,219
	75,620	73,219

The auditors did not receive any other benefits (2022: nil).

19. Franking credits

There are no franking credits available for distribution (2022: nil).

20. Commitments

20 (i). Expenditure commitments

The Group has expenditure commitments at the end of the financial year for short term non-cancellable operating lease office rental payments, not included as liabilities in the financial statements at note 10. The inclusion of long term operating lease office rentals payments under AASB 16 now classified as liabilities for the year end 30 June 2023.

(a) Commitments for office lease rental payments

	Consolidated	
	2023 US$	**2022 US$**
Not longer than 1 year	**19,820**	20,594
	19,820	20,594

(b) Exploration lease expenditure commitments

The Group has no exploration lease commitments at the end of the financial year as the leasing arrangements of the Gulf of Mexico blocks do not require firm work programme commitments.

(c) Well expenditure commitments

The Group has a financial commitment as at balance date for the budgeted drilling rig expenditure component of the SM58 G4 and G6 wells.

Commitments for drilling of oil and gas wells		
Not longer than 1 year	**3,778,000**	15,880,680

21. Controlled entities

The following entities are controlled by Byron Energy Limited and they have been consolidated into the financial statements for the consolidated entity:

Name	Country of domicile	Class of share	Percentage beneficially owned
Byron Energy (Australia) Pty Ltd	Australia	Ordinary	100%
Byron Energy Inc	USA	Ordinary	100%
Byron Energy LLC	USA	Ordinary	100%

22. Foreign currency translation

The exchange rates utilised in the translation of the parent entity group Australia dollar amounts to United States of America dollars are as follows:

	2023	**2022**
Spot rate at 30 June	**0.6630**	0.6889
Average rate for year	**0.6734**	0.7258

23. Cash flow reconciliation

	Consolidated 2023 US$	2022 US$
(a) Reconciliation of profit from ordinary activities after tax to net cashflows from operations		
Profit for the year	**22,715,727**	22,215,308
Non cash flows in operating result:		
Amortisation oil and gas properties	**11,442,908**	11,578,395
Depreciation of property, plant, equipment	**8,291**	32,749
Depreciation of right of use assets	**451,948**	451,948
Impairment expense	**3,123,647**	3,082,807
Equity settled share based payments	**133,026**	1,599,464
Finance cost of leased assets	**85,724**	130,542
Net foreign exchange (gain)/loss on A$ loans	**(54,390)**	(132,090)
Unwinding of discount on rehabilitation of oil and gas properties	**182,304**	116,979
Foreign exchange differences arising on translation of the parent entity group	**(4,186)**	(5,261)
	38,084,999	39,070,841
Movements in working capital		
(Increase)/decrease in assets:		
Trade and other receivables	**3,378,233**	(3,313,982)
Other assets	**(2,038,973)**	187,349
Increase/(decrease) in liabilities:		
Trade and other payables	**1,106,735**	624,619
Provisions	**32,610**	43,583
Net cash from operating activities	**40,563,604**	36,612,410
(b) Reconciliation of cash		
Cash and cash equivalents comprise:		
Cash and bank balances	**4,223,877**	14,087,032

(c) Financing facility

The Group had finance facilities at balance date consisting of loans from directors and shareholders that are fully drawn, loans from a third party provider and an insurance premium financing facility.

(d) Non-cash financing and investing activities

There were no non-cash financing or investing activities during the financial year.

24. Contingent liabilities

The directors are of the opinion that the recognition of a provision is not required in respect of the following matters, as it is not probable that a future sacrifice of economic benefits will be required.

(a) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC.

(b) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under (i) an ISDA Master Agreement dated 21 May 2020 between Byron Energy Inc. and Shell Trading Risk Management, LLC and (ii) the Master Crude Purchase and Sale Agreement between dated 26 November 2020 between Byron Energy Inc. and Shell Trading (US) Company.

(c) Supplemental Bonding Requirements by the BOEM

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to satisfy lease obligations, including decommissioning activities on the OCS. As of the date of this report, the Company is in compliance with its financial assurance obligations to the BOEM and has no outstanding BOEM orders related to assurance obligations. Byron and other offshore Gulf of Mexico producers may in the ordinary course receive future demands for financial assurances from the BOEM as the BOEM continues to re-evaluate its requirements for financial assurances.

(d) Surety Bond Issuers' Collateral Requirements

The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for exploration and development drilling and plugging and abandonment activities. Byron may be required to post collateral at any time pursuant to the terms of its agreement with sureties under its existing bonds, if they so demand at their discretion. As at 30 June 2023, Byron had collateral bond holdings of US$ 8,118,356 (2022: US$ 5,618,356), of which US$ 3,054,542 (2022: US$ 1,783,007) was cash collateralised.

(e) Other Claims

Claims or contingencies may arise related to matters occurring prior to Byron's acquisition of properties or related to matters occurring subsequent to Byron's sale of properties. In certain cases, Byron has indemnified the sellers of properties it has acquired, and in other cases, it has indemnified the buyers of properties sold.

From time to time the Company may be involved in litigation arising out of the normal course of business. The Company is not involved in any ligation, the outcome of which would have a material effect on its consolidated financial position, results of operations or liquidity.

In addition, the Company and its oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases which Byron operate and/or participate. As a result of these joint interest audits, amounts payable or receivable by the Company for costs incurred or revenue distributed by the operator or by the Company on a lease may be adjusted, resulting in adjustments to Byron's net costs or revenues and the related cash flows. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognised by the joint account. Byron does not believe any such adjustments will be material.

(f) Decommissioning Obligations

The Company has divested various leases, wells and facilities located in the U.S. Gulf of Mexico where the purchasers typically assume all abandonment obligations acquired. Certain of these counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Under certain circumstances, regulations or federal laws could require the Company to assume such obligations.

Although it is reasonably possible that the Company could receive state or federal decommissioning orders in the future or be notified of defaulting third parties in existing leases, the Company cannot predict with certainty, if, how or when such orders or notices will be resolved or estimate a possible loss or range of loss that may result from such orders. However, the Company could incur judgments, enter into settlements or revise our opinion regarding the outcome of certain notices or matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

25. Share-based payments

Movements in share-based payments options

	Consolidated	
	2023 US$	**2022 US$**
The aggregate share-based payments paid as remuneration for the financial year are set out below:		
Details of share-based payments:		
The extension of interest free loans previously made to executives, staff and consultants for the conversion of share options to fully paid ordinary shares in 2019	**133,026**	–
Fair value of options granted to staff	**–**	84,517
Interest free loans made to executives, staff and consultants for the conversion of share options to fully paid ordinary shares	**–**	1,514,947
Expense arising from share-based payments paid as remuneration	**133,026**	1,599,464

No share options were exercised and converted to fully paid shares during the financial year (2022: 41,100,000). There are no Employee Share Option plans in place.

	2023 Number	**2023 Exercise price**	**2022 Number**	**2022 Exercise price**
Balance at beginning of year	**2,000,000**		41,100,000	
Granted during the year	**–**		2,000,000	
Exercised during the year	**–**		(41,100,000)	
Balance at end of year	**2,000,000**		2,000,000	
Exercisable at end of year	**2,000,000**	**A$0.16c**	2,000,000	A$0.16c

Weighted average remaining contractual life

The 2,000,000 share options have an expiry of 550 days remaining.

Director and key management personnel equity share options

The were no share based payment options held at the end of the reporting year by directors and/or key management personnel.

Calculation of the fair value to extend loans that previously funded conversion of equity share options into fully paid shares

Inputs into the model	Two year extension of loans for 9,500,000 share options previously converted to fully paid ordinary shares to directors, staff and consultants as at 31 December 2022
Share option exercise price	A$0.25
Share price 31 December 2022	A$0.115
Number of options	9,500,000
Volatility	69.56%
Time maturity of underlying option	2 years
Risk-free interest rate	3.416%

Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2023

26. Key management personnel compensation

Total aggregate remuneration of directors and key management personnel.

	Short term employee benefits				Post employment benefits	Share-based payments	
	Salaries and fees US$	Short term cash incentive US$	Other benefits US$	Service agreements US$	Superannuation US$	Interest free loans to exercise share options US$	Total US$
Year 2023	**1,251,981**	**–**	**62,935**	**545,816**	**31,003**	**119,024**	**2,010,759**
Year 2022	1,143,292	–	67,228	530,106	28,651	1,134,034	2,903,311

More detailed information on remuneration and retirement benefits of directors is disclosed in the Remuneration Report.

27. Related party transactions

The following related party transactions were made during the financial year ended 30 June 2023:

(a) In March 2019, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with four of the Company's directors for loans from companies controlled by directors or loans from directors, for a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in November 2019, however during the year ended 30 June 2023 the directors agreed to extend the loan repayment date to 31 March 2025 and interest payments have been made on a quarterly basis. The individual directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, a director of the Company, provided an unsecured loan of A$1,400,000 to the Company and interest paid for the financial year to June 2023 was A$ 140,000, plus A$11,507 has been accrued as at 30 June 2023;
- Clapsy Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2023 was A$17,500, plus A$1,438 has been accrued as at 30 June 2023;
- Poal Pty Ltd, a company controlled by Mr Paul Young, a director of the Company, provided an unsecured loan of A$175,000 to the Company and interest paid for the financial year to June 2023 was A$17,500, plus A$1,438 has been accrued as at 30 June 2023;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to June 2023 was US$100,000, plus US$8,219 has been accrued as at 30 June 2023; and
- Mr Charles Sands, a director of the Company, provided an unsecured loan of US$1,000,000 to the Company and interest paid for the financial year to 30 June 2023 was US$90,000 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2023.

Subsequent to 30 June 2023, the directors agreed to further extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum affective 1 August 2023. With the additional 2% to be capitalised until loan repayment date of 31 December 2025.

(b) As at 30 June 2023, there are also non-recourse loans made to the Company to the following related parties as detailed below.

(i) In January 2020 the Company provided unsecured 3 year interest free loans to the executive directors to fund the acquisition of the shares issued as a consequence of the exercise of options. The interest free loans were approved by shareholders at the Company's 2019, annual general meeting held on 29 November 2019. The 3 year term of these loans were extended by a further 2 years to 31 December 2024, following approval by shareholders at the Company's 2022 annual general meeting held on 29 November 2022.

Key management personnel (borrower)	**Principal sum (A$)**	**Interest rate %**	**Term**
Maynard Smith	625,000	Nil	2 years
Prent Kallenberger	625,000	Nil	2 years
William Sack	625,000	Nil	2 years

(ii) In January 2022, the Company provided unsecured 3 year interest free loans to the executive directors to fund the acquisition of the shares issued as a consequence of the exercise of options, treated as treasury shares for accounting purposes. The interest free loans were approved by shareholders at the Company's 2021, annual general meeting held on 29 November 2021, and granted to key management personnel during the 2022 financial year. Loans outstanding as of 30 June 2023 are:

Key management personnel (borrower)	**Principal sum (A$)**	**Interest rate %**	**Term**
Maynard Smith and associates	1,596,000	Nil	3 years
Prent Kallenberger and associates	1,596,000	Nil	3 years
William Sack and associates	1,596,000	Nil	3 years

At the end of the term, each borrower is required to repay the amounts outstanding under the loans. If a borrower does not repay a loan, the Company may demand that a borrower dispose of sufficient loan funded shares to satisfy up to the total amount owing under the loan. The Company's recourse against each borrower for repayment of the loans is limited to the proceeds of the loan funded shares.

28. Financial instruments

The consolidated entity's financial instruments consist mainly of cash and cash equivalents, trade and other receivables, security deposits, trade and other payables and secured borrowings. The main risks the consolidated entity is exposed to through its financial instruments are interest rate risk, foreign currency risk, liquidity risk and credit risk.

This note presents information about the consolidated entity's exposure to each of the above risks and processes for measuring and managing the risks and the management of capital.

	Consolidated	
Categories of financial instruments	**2023 US$**	**2022 US$**
Financial assets		
Cash and cash equivalents	**4,223,877**	14,087,032
Trade and other receivables	**4,379,508**	7,594,887
Bonds and security deposits	**3,060,323**	1,789,014
	11,663,708	23,470,933
Financial liabilities		
Trade and other payables	**3,970,349**	17,122,661
Prepaid oil revenue	**–**	11,000,000
Insurance premium financing	**2,194,155**	1,701,944
Loans from related parties	**3,392,300**	3,446,690
Crescent promissory note	**–**	4,830,114
	9,556,804	38,101,409

(a) Capital risk management

The Group manages its capital to ensure that entities in the Group will be able to continue as a going concern while maximising the return to shareholders. The Group's capital structure consists of: (i) equity comprising issued capital, reserves and accumulated losses, (ii) as required, unsecured borrowings from related parties and shareholders and (iii) secured borrowings from independent third parties on commercial terms.

During the 2023 financial year, no dividends were paid (2022: nil).

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements.

(b) Credit risk exposure

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. The Group has adopted a policy of only dealing with creditworthy counterparties as a means of mitigating the risk of financial loss from defaults.

The Group has a credit exposure to the party that purchases its oil production from the SM71 and SM58 leases. There are no risk mitigation strategies in place, however the purchasing company is a large global energy corporation, so the risk of financial default is considered low. Apart from this credit risk exposure, the Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties having similar characteristics. The credit risk on liquid funds is limited as the counterparties are banks with high credit ratings assigned by international credit rating agencies.

The carrying amount of financial assets recorded in the financial statements, net of any allowances for losses, represent the Group's maximum exposure to credit risk.

(c) Liquidity risk management

The Group manages liquidity risk by maintaining adequate cash reserves and if required, standby credit facilities to meet commitments when they fall due. Management continuously monitors cash forecasts to manage liquidity risk.

Liquidity, credit and interest risk tables

The following table details the Group's remaining contractual maturity for its financial assets.

Consolidated financial assets	Weighted average effective interest rate %	Less than 1 month US$	1 month to 3 months US$	3 months to 12 months US$	1-5 years US$
2023					
Non-interest bearing	**–**	**3,966,186**	**344,522**	**68,800**	**–**
Non-interest rate bearing bonds	**–**	**–**	**–**	**5,781**	**–**
Interest rate bearing bonds	**1.02**	**–**	**–**	**–**	**3,054,542**
Variable interest rate instruments	**1.06**	**4,223,877**	**–**	**–**	**–**
2022					
Non-interest bearing	–	7,373,049	42,103	77,400	102,335
Non-interest rate bearing bonds	–	–	–	6,007	–
Interest rate bearing bonds	0.05	–	–	–	1,783,007
Variable interest rate instruments	0.01	14,087,032	–	–	–

The table below details the Group's remaining contractual maturities for its financial liabilities. The following are future contractual cash payments of financial liabilities, including estimated interest payments.

Consolidated financial liabilities	Weighted average effective interest rate %	Less than 1 month US$	1 month to 3 months US$	3 months to 12 months US$	1-5 years US$
2023					
Non-interest bearing	**–**	**2,488,163**	**1,157,186**	**–**	**325,000**
Fixed interest rate instruments	**6.95**	**249,038**	**506,452**	**1,438,665**	**–**
Related party liabilities	**10.00**	**–**	**–**	**–**	**3,392,300**
2022					
Non-interest bearing	–	12,172,999	4,581,256	43,406	325,000
Prepaid oil revenue	10.41	–	1,375,000	9,625,000	–
Fixed interest rate instruments	3.91	211,792	432,287	1,057,865	–
Related party liabilities	10.00	–	–	3,446,690	–
Crimson loan	15.00	966,022	1,932,046	1,932,046	–

(d) Fair values

The directors consider that the carrying amounts of financial assets and financial liabilities recorded at cost less any accumulated impairments in the financial statements approximates their fair values.

The fair values of financial assets and financial liabilities are determined as follows:

(i) other financial assets and financial liabilities are determined in accordance with generally accepted pricing models.

28. Financial instruments continued

(e) Interest rate risk management

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's cash and cash equivalents with a floating interest rate. The Group is not currently engaged in any hedging or derivative transactions to manage interest rate risk. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 30 June 2023, the Group had no loans outstanding with a variable interest rate as the insurance premium funding, a secured third party loan and director/shareholder loans, all have applicable fixed interest rates. As such, the fixed interest rate loans have an interest risk if variable and/or new loan interest rates are below the fixed loan interest rates.

Interest rate sensitivity analysis

A sensitivity analysis has been determined based on the exposure to interest rates at reporting date with the stipulated change taking place at the beginning of the financial year and held constant throughout the reporting period.

At reporting date, if interest rates had been 50 basis points higher or lower and all other variables were held constant, the Group's net profit would increase by US$45,777 (2022: US$45,576) for an increase of 50 basis points, conversely a decrease of 50 basis points would result in a decrease of US$45,777 (2022: US$45,576) to the net profit. This is mainly due to the Group's exposure to variable interest rates on cash and cash equivalents.

(f) Foreign currency risk management

The Group incurs costs in USA dollars and Australian dollars and holds the majority of liquid funds in USA dollars.

Fluctuations in the Australian dollar/USA dollar exchange rate can impact the performance of the consolidated entity. The consolidated entity is not currently engaged in any hedging or derivative transactions to manage foreign currency risk. As cash inflows and cash outflows are predominately denominated in USA dollars, with the exception of Australian dollar denominated equity funding, surplus funds are primarily held in USA dollars.

The carrying amounts of the Group's foreign currency denominated monetary assets and monetary liabilities at the end of the reporting period are as follows.

	Monetary Assets		Monetary Liabilities	
Consolidated	**2023 $**	**2022 $**	**2023 $**	**2022 $**
USA currency denominated	**11,538,629**	23,338,897	**7,890,833**	36,450,522
Australian currency denominated	**188,657**	191,663	**2,512,777**	2,396,410

The following table details the Group's sensitivity to a 10% increase and decrease in the US$ against the A$.

A positive number below indicates an increase in profit or equity where the US dollar strengthens 10% against the relevant currency. For a 10% weakening of the US dollar against the relevant currency, there would be a comparable negative impact on the profit or equity. The impact is mainly due to the Australian group of holding companies incurring and settling expenses and outgoings in Australian dollars.

	Australian dollar impact on profit/loss	
Consolidated	**2023 US$**	**2022 US$**
Profit or equity	**131,096**	482,504

(g) Commodity price risk

The Group's exposure to the risk of changes in commodity price relates primarily to the Group's sales of crude oil. The Group currently manages these risks through US$ denominated oil price hedges. Although no derivatives were entered into during the financial year, changes in the fair value of these derivatives would be recognised immediately in the profit and loss and other comprehensive income, having regard to whether they are defined as accounting hedges.

At reporting date, if the West Texas Intermediate ("WTI") price per barrel had been US$5.00 per barrel higher or lower and excluding hedged price oil barrels, with all other variables were held constant, the Group's net profit would increase by US$2,506,100 (2022: US$1,953,170) for an increase of US$5.00 per WTI oil barrel, conversely a decrease of US$5.00 per WTI oil barrel would result in a decrease of US$2,506,100 (2022: US$1,953,170) to the net profit.

29. Segment information

Management has determined based on the reports reviewed by the executive management group (the chief operating decision makers) and used to make strategic decisions, that the Group operates within one business segment of oil and gas exploration, development and production; and one geographical segment, the shallow waters of the Gulf of Mexico, United States of America.

The geographical locations of the Group's non-current assets are United States of America US$133,124,393 (2022: US$127,202,217) and Australia US$5,580 (2022: US$6,122).

30. Interests in joint operations

As at 30 June 2023, Byron Energy Inc, a wholly owned subsidiary of the Company was a party, to the following joint operations:

(i) SM71 Offshore Operating Agreement with Otto Energy (Louisiana) LLC covering all of Block 71, South Marsh Island Area, to explore, develop, produce and operate the lease. Byron Energy Inc is the designated operator of SM71 and owns a 50% WI and a 40.625% NRI in the block, with Otto Energy (Louisiana) LLC holding an equivalent WI and NRI in the block. Byron is the operator;

(ii) On 6 March 2019, Byron purchased from Fieldwood Energy LLC, a 53.00% non-operated WI/44.167% NRI in the SM58 Apache E1 well and E Platform located on SM69. WT Offshore, Inc. (previously Ankor E&P Holdings Corporation) is the operator and holds a 47.00% WI in the well and platform; and

(iii) 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.

31. Parent entity information

Financial position	2023 US$	2022 US$
Assets		
Current assets	**80,094**	89,972
Non-current assets	**122,912,964**	126,799,158
Total assets	**122,993,058**	126,889,130
Liabilities		
Current liabilities	**186,370**	3,579,017
Non-current liabilities	**3,392,300**	–
Total liabilities	**3,578,670**	3,579,017
Net assets	**119,414,388**	123,310,113
Equity		
Issued capital	**138,453,327**	138,453,327
Accumulated losses	**(15,023,047)**	(13,999,564)
Foreign currency translation reserve	**(10,175,169)**	(7,169,901)
Share option reserve	**6,159,277**	6,026,251
Total equity	**119,414,388**	123,310,113
Financial performance		
Profit/(Loss) for the year	**(1,023,483)**	(2,385,813)
Other comprehensive income/(loss)	**(3,005,268)**	(7,367,150)
Total comprehensive profit/(loss) for the financial year	**(4,028,751)**	(9,752,963)

Expenditure commitments

The parent entity has no expenditure commitments at the end of the 2023 financial year (2022: nil).

31. Parent entity information continued

Guarantees

There were no guarantees entered into during the year by the parent entity in relation to the debts of its subsidiaries except for (i) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Secured Promissory Note between Byron Energy Inc and Crimson Midstream Operating, LLC, effective as of 3 December 2019; and (ii) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under an ISDA Master Agreement dated 21 May 2020 between Byron Energy Inc. and Shell Trading Risk Management, LLC and the Master Crude Purchase and Sale Agreement between dated 26 November 2020 between Byron Energy Inc. and Shell Trading (US) Company. In addition, Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC.

Contingent liabilities

The parent entity had no contingent liabilities at 30 June 2023 (2022: nil), other than those listed in Note 24 – Contingent liabilities.

32. Subsequent events

Subsequent to the end of the financial year the following has occurred:

(i) on 1 August 2023, Byron announced to the ASX that: (i) it had closed a forward sale loan facility ("Prepayment Facility") for up to US$22 million with a supermajor, Byron's sole purchaser of oil and primary hedge counterparty, to fund the upcoming SM58 development program expected to commence in mid-August 2023 pending rig release by the current operator; (ii) The US$31 million development program is to be funded by a combination of internally generated funds and the US$22 million loan facility provided by the lender, and (iii) The multi-draw facility includes a US$10 million initial draw prior to September 30th followed by an optional second draw of up to US$12 million within 90 days intended to fund completion activities contingent upon success;

(ii) the outstanding directors' and shareholder loans of approximately US$3.4 million, were extended from 31 March 2025 to 31 December 2025; subsequent to 30 June 2023, the directors and a shareholder agreed to further extend the loan repayment date from 31 March 2025 to 31 December 2025 in consideration for an increase in the interest rate from 10% per annum to 12% per annum affective 1 August 2023 with the additional 2% to be capitalised until loan repayment date of 31 December 2025;

(iii) On 14 August 2023, Byron announced to the ASX that the Enterprise 264 jack-up drilling rig was on location preparing to drill two wells, Tiger Trout (G4) and Gila Trout (G6) in SM58;

(iv) On 28 August 2023, Byron released its annual reserves report;

(v) On 8 September 2023, Byron announced that the SM58 G6 well was drilled to 10,465 feet MD/8,667 feet TVD and logged two oil sands with the L2 Sand, logging 32 feet MD net oil and gas pay (23 feet TVT) and the I1 Sand logging 12 feet MD oil pay (10 feet TVT);

(vi) On 15 September, 2023 Byron announced it had received the first draw of US$ 10 million under the Prepayment Facility and had entered into oil price hedges comprising:

- Hedge 1 – 250 bopd over a period of 24 months (September 2023 – August 2025) at an average West Texas Intermediate (WTI) base price of approximately US$74.68, with this average price to be paid each month of the period; and
- Hedge 2 – 225 bopd over a period of 23 months from 31 October 2023 – 31 August 2025 at an average WTI base price of approximately US$75.00/bopd to be paid at the contracted monthly strip price during the period; and

(vii) On 25 September 2023, Byron announced that the SM58 G4 well was drilled to 10,169 feet MD/9,017 feet TVD and logged an oil sand with the K4(B65) sand target, logging 82 feet MD net oil pay (59 feet TVT).

Except for the above, there have not been any other matters or circumstances occurring subsequent to the end of the financial year that have significantly affected, or may significantly affect the operations of the Group, the results of those operations, or the state of affairs of the company in future financial period.

Directors' Declaration

The directors of Byron Energy Limited declare that in the opinion of the directors:

(a) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable;

(b) the attached financial statements are in compliance with International Financial Reporting Standards as stated in note 1 to the financial statements;

(c) the attached financial statements and notes thereto are in accordance with the *Corporations Act 2001*, including compliance with accounting standards and giving a true and fair view of the financial position and performance of the consolidated entity; and

(d) the directors have been given the declarations required by section 295A of the *Corporations Act 2001*.

Signed in accordance with a resolution of the directors of Byron Energy Limited made pursuant to section 295(5) of the *Corporations Act 2001*.

On behalf of the directors

D. G. Battersby
Chairman

29 September 2023

Independent Auditor's Report

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Independent Auditor's Report to the members of Byron Energy Limited

Report on the Audit of the Financial Report

Opinion

We have audited the financial report of Byron Energy Limited (the "Company") and its subsidiaries (the "Group") which comprises the consolidated statement of financial position as at 30 June 2023, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies, and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the *Corporations Act 2001*, including:

- Giving a true and fair view of the Group's financial position as at 30 June 2023 and of its financial performance for the year then ended; and
- Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for Opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the "Code") that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the directors of the Company, would be on the same terms if given to the directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

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Key Audit Matter	How the scope of our audit responded to the Key Audit Matter

Carrying value of oil and gas properties
 	
For the year ended 30 June 2023 the Group has recognised oil and gas property assets of US$127.975m. Management conducts an impairment indicator assessment and performs impairment testing where indicators have been identified. As at 30 June 2023, the Group had a market capitalisation deficiency which is considered to be a pervasive indicator of impairment and as a result all the cash generating units of the Group were assessed for impairment. This was performed through a 'fair value less costs to sell' valuation methodology. In determining the fair value less costs to sell, management is required to exercise judgement to determine the future cash flow projections, which include:
• forecast cash flows from operations;
• forecast capital expenditure;
• discount rate used to present value the future cash flows.
Management utilise the work performed by external independent petroleum engineers to estimate future production and associated cashflows.
 	
The carrying value of the oil and gas properties is also impacted by the annual amortisation charge. When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a unit of production basis over the remaining proved and probable recoverable reserves. The remaining reserves are measured by external independent petroleum engineers.
The measurement of this amortisation is subject to certain assumptions including:
• The level of future proved and probable recoverable reserves; and
• The future capital expenditure required to access the reserves.
 	
Given the judgements and assumptions applied we consider this to be a key audit matter.
	Our procedures included, but were not limited to:
	
	• Evaluating the appropriateness of management's identification of the Group's CGUs determined for impairment testing;
	• Evaluating the 'fair value less costs to sell' discounted cash flow model developed by management to assess the recoverable amount of each CGU;
	• In conjunction with our internal valuation specialists:
	    • assessing the reasonableness of key valuation model inputs including discount rates; and
	    • testing the mathematical accuracy of the model.
	• Performing a range of sensitivity analyses on a number of key assumptions including changes to forecast production, commodity prices, operating and capital expenditure and discount rates;
	• Obtaining and assessing management's external specialist report used to estimate the level of proven and probable oil and gas reserves and future development capital expenditure;
	• Assessing the objectivity, expertise, and experience of management's external specialist to support the assumptions used;
	• Testing the metered production usage in the current year to independent third-party reports;
	• Recalculating the mathematical accuracy of the amortisation recognised; and
	• Assessing the adequacy of the disclosures in note 8 to the financial statements.

Other Information

The directors are responsible for the other information. The other information comprises the information included in the Group's annual report for the year ended 30 June 2023, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Directors for the Financial Report

The directors are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

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In preparing the financial report, the directors are responsible for assessing the Group’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor’s Responsibilities for the Audit of the Financial Report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group’s internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

- Conclude on the appropriateness of the directors’ use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Group to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the financial report. We are responsible for the direction, supervision and performance of the Group’s audit. We remain solely responsible for our audit opinion.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

From the matters communicated with the directors, we determine those matters that were of most significance in the audit of the financial report of the current period and are therefore the key audit matters. We describe these matters in our auditor’s report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included on pages 40 to 45 of the Director's Report for the year ended 30 June 2023.

In our opinion, the Remuneration Report of Byron Energy Limited, for the year ended 30 June 2023, complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Deloitte Touche Tohmatsu

DELOITTE TOUCHE TOHMATSU

Jane Fisher
Partner
Chartered Accountants
Melbourne, 29 September 2023

ASX Additional Information

Distribution of Equity Securities

As at 10 October 2023 the Company had a total of 1,081,395,102 Ordinary Shares on issue and 2,000,000 Options on issue comprising:

Quoted Ordinary Shares

1,081,395,102 fully paid Ordinary Shares are held by 4,893 shareholders. All issued ordinary shares carry one vote per share without restriction. Every member at a meeting of shareholders shall have one vote and up on a poll each share shall have one vote.

Unquoted Options on issue

2,000,000 options are held by 2 option holders. exercisable on or before 31 December 2024 at an exercise price of $A0.16 cents each.

There are no voting rights attached to these options.

The number of shareholders, by size of holding and the total number of quoted shares on issue:

Size of holding	No. of holders	No. of shares
1 – 1,000	1,013	401,874
1,001 – 5,000	1,137	3,123,410
5,001 – 10,000	621	4,697,315
10,001 – 100,000	1,350	50,825,324
100,001 and over	772	1,022,347,179
Total Holders	**4,893**	**1,081,395,102**

The number of security investors holding less than a marketable parcel of securities is 2,197 with a combined total of 3,768,427 securities.

The number of option-holders, by size of holding and the total number of unquoted options on issue:

Size of holding	No. of holders
1 – 1,000	
1,001 – 5,000	
5,001 – 10,000	
10,001 – 100,000	
100,001 and over	2
Total	**2**

Shares held in Voluntary Escrow

Shares that are subject to voluntary escrow arrangements are as follows: A total of 41,100,000 shares are subject to voluntary escrow, commencing on 31 December 2021, and ending on 5pm (Sydney time) on the date that is the earlier of: (i) repayment of all of the outstanding loan under the Option Exercise Loan; and (ii) disposal of all of the restricted securities in accordance with the Voluntary Escrow Deed. These shares are already quoted on the ASX. The shares in voluntary escrow are held by executive directors, staff and contractors.

Substantial Shareholders

Set out below are the names of the substantial holders and the number of equity securities held by those substantial holders (including those equity securities held by their associates).

Name of holder	No. of ordinary shares held	Percentage of issued capital
Douglas Battersby (and associates)	57,800,568	5.34%

20 Largest Shareholders

As at 10-10-2023

Byron Energy Limited

Fully Paid Ordinary Shares

Name	Balance	%
BNP PARIBAS NOMINEES PTY LTD <IB AU NOMS RETAILCLIENT DRP>	84,687,441	7.831%
VERUSE PTY LIMITED	44,435,985	4.109%
J & A VAUGHAN SUPER PTY LTD <J & A VAUGHAN SUPER A/C>	38,635,066	3.573%
GEOGENY PTY LTD <M AND V SMITH SUPER A/C>	32,627,836	3.017%
ELMSLIE SUPERANNUATION COMPANY PTY LTD <ELMSLIE FAMILY S/F A/C>	28,269,844	2.614%
MR CHARLES SANDS	20,382,409	1.885%
CITICORP NOMINEES PTY LIMITED	19,232,770	1.779%
WALLEROO PTY LTD	18,828,791	1.741%
MR MATTHEW DOMINELLO	16,570,000	1.532%
HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	15,878,284	1.468%
CLAPSY PTY LTD <BARON SUPER FUND A/C>	15,354,350	1.420%
MR WILLIAM R SACK	13,294,445	1.229%
GEOGENY PTY LIMITED	13,214,045	1.222%
BARRIJAG INVESTMENTS PTY LIMITED	12,645,000	1.169%
MR JOHN SANDS <THE JOHN SANDS REVOCABLE A/C>	12,080,972	1.117%
AGRICO PTY LTD <PALM SUPER FUND A/C>	11,696,384	1.082%
MR PRENT KALLENBERGER & MRS MOLLY KALLENBERGER	11,608,847	1.074%
FITZROY RIVER CORPORATION LIMITED	11,210,089	1.037%
JETAN PTY LTD	10,550,001	0.976%
POAL PTY LTD <BARAIN SUPER FUND A/C>	9,791,298	0.905%
Total Securities of Top 20 Holdings	440,993,857	40.780%
Total of Securities	**1,081,395,102**	

Corporate Directory

Directors

Doug Battersby (Non Executive Chairman)
Maynard Smith (Executive Director & CEO)
Prent Kallenberger (Executive Director)
William Sack (Executive Director)
Charles Sands (Non-Executive)
Paul Young (Non-Executive)

Chief Executive Officer

Maynard Smith

Chief Financial Officer and Company Secretary

Nick Filipovic

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