Positioned for maximum opportunity

Annual Report 2022

Contents

Highlights

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

SM71, SM58 and SM69 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

Gross SM58 production (including E2 well)

2,206 MMcf

220 Mbo

Over 2 Bcf of gas and 220,000 barrels of oil produced for year ended 30 June 2022

Gross SM71 production

599 MMcf

783 Mbo

Approximately 783,000 barrels of oil and 0.6 Bcf of gas produced for year ended 30 June 2022

Reserves as at 30 June 2022 (net)

1P 13.2 Mmboe (73% oil)

2P 18.6 Mmboe (74% oil)

3P 23.7 Mmboe (76% oil)

Chairman's Letter

Dear Shareholder,

The year ending 30 June 2022 saw another strong rally in oil and gas prices, providing a positive backdrop to our operations in the Gulf of Mexico, USA. Higher prices together with increased production of oil resulted in record annual production, revenue and earnings for Byron.

West Texas Intermediate ("WTI"), the US marker oil price, increased from US$73.52 on 30 June 2021 to US$107.76 on 30 June 2022, an increase of 47%. The Henry Hub natural gas mmbtu spot price rose from US$3.79 on 30 June 2021 to US$6.54 on 30 June 2022, an increase of 73%.

While the complete production and financial information is contained in this annual report, I want to emphasise the fact that we produced and sold approximately 0.5 million barrels of oil and over 2.0 billion cubic feet of gas during the 2022 year, generating net revenue of approximately US$53.2 million.

Importantly, once again we operated the Company's production facilities and wells with an excellent safety and environmental record.

The 2022 financial year was the second year of material oil price gains with 2021 year also having enjoyed a strong recovery from COVID-19 induced lows in 2020.

The oil price increase in 2022 was largely driven by a resurgent demand post COVID-19, and the Russia-Ukraine war, which began with the Russian invasion of Ukraine in February 2022. This resulted in sanctions on Russia's oil and gas exports creating energy insecurity around the globe, exacerbating already tight oil supplies created by years of underinvestment by oil companies.

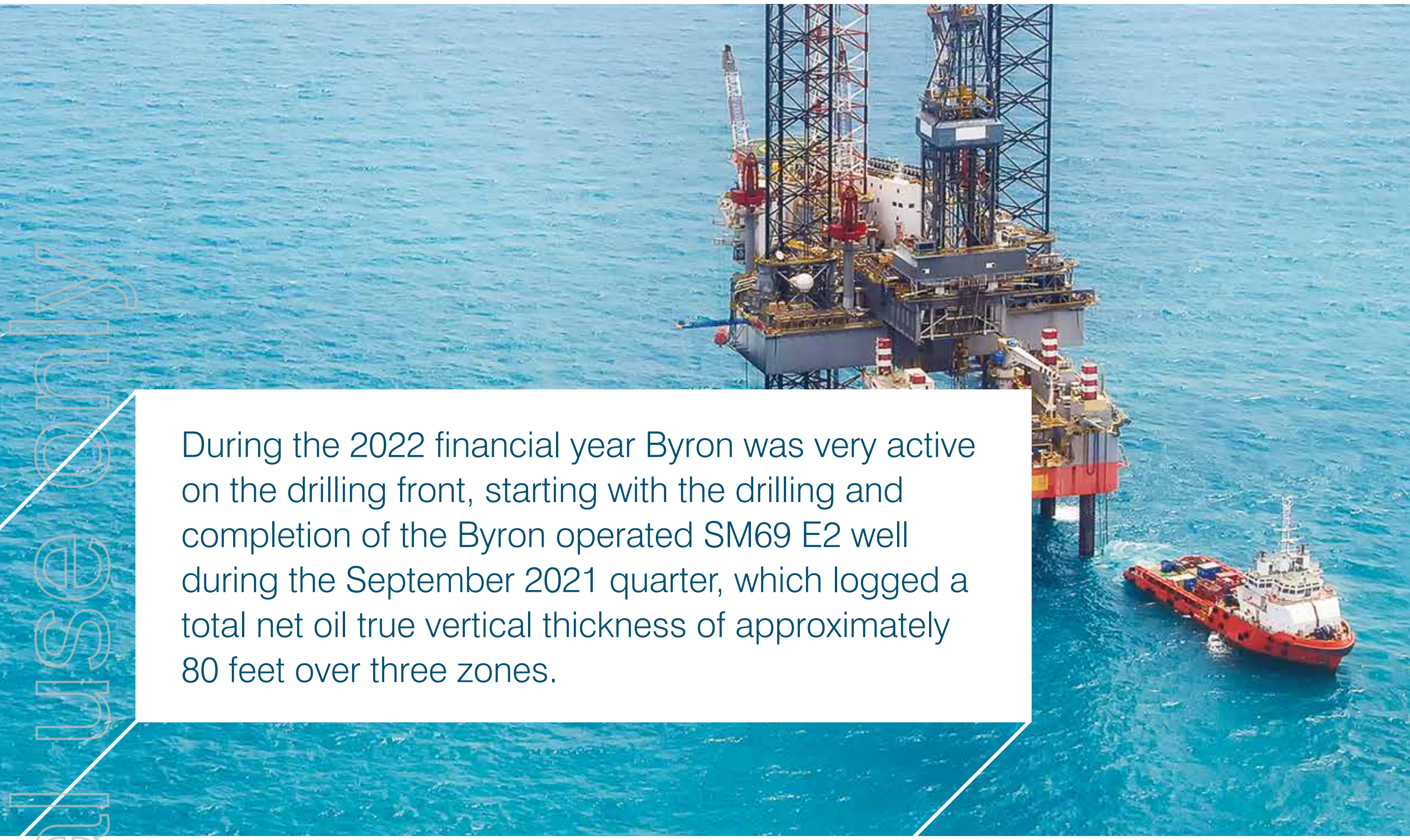
Looking ahead, the relatively unstable international environment plus the continuing generally low level of exploration activity discouraged by oil companies and governments fixated on a climate change agenda have the potential to maintain oil and gas prices at elevated levels during the coming years.

Performance of energy equities improved during 2022 once again lagged oil and gas prices with the ASX Energy index (ASX code XEJ) increasing by approximately 18% between 30 June 2021 and 30 June 2022 compared to a near 50% increase in oil prices and more than 70% increase in gas prices over the same period.

With a favourable oil and gas pricing environment bolstering its cash flows, Byron continued to add to its proved developed producing reserves in the Gulf of Mexico, focused on our operated South Marsh Island Block 58 and where Byron commenced production in September 2020.

During the 2022 financial year Byron was very active on the drilling front, starting with the drilling and completion of the Byron operated SM69 E2 well during the September 2021 quarter, which logged a total net oil true vertical thickness of approximately 80 feet over three zones.

Production from the Company's E2 well began on 21 October 2021 with oil and gas produced from the E2, located on SM69 E platform, flowing to the Byron operated SM58 G platform where separation occurs before oil and gas are sent to sales pipelines.



During the 2022 financial year Byron was very active on the drilling front, starting with the drilling and completion of the Byron operated SM69 E2 well during the September 2021 quarter, which logged a total net oil true vertical thickness of approximately 80 feet over three zones.

During the June 2022 quarter Byron successfully drilled the SM58 G3 and the SM58 G5 wells. The G3 well drilled the Rainbow Trout prospect and the G5 well drilled the Smoked Trout prospect.

Both G3 and G5 wells were completed for production during the September 2022 quarter, adding substantially to production output from the SM58 G platform.

As of 30 June 2022, the SM58 G facility has produced approximately 6.8 Bcfg and 0.3 million barrels of oil (gross) on a cumulative basis from three wells (G1, G2 and E2 wells).

Byron operated SM71 project recorded another strong performance during the 2021/22 year producing approximately 319,000 barrels of oil and 246,000 mmcf of gas net to Byron.

From March 2018 until the end of June 2022, a total of 4.1 mmbo and 5.1 Bcf of gas have been produced, making SM71 the number two ranked producing block on the Gulf of Mexico Shelf over that period. The SM71 F3 (F3) well ranks number one and the SM71 F1 (F1) well ranks number three among active producing oil wells on the Shelf since March 2018.

On 14 September 2022, we released our 30 June 2022 reserves and resources statement. Our reserves and resources position as at 30 June 2022 shows Remaining 1P Reserves, net to Byron, of 9.6 Mmbbl of oil and 21.7 Bcf of gas with Remaining 2P Reserves, net to Byron, of 13.8 Mmbbl of oil and 28.7 Bcf of gas, a very solid reserve position. Pleasingly Byron was able to substantially increase its Net Proved Developed Reserves (producing and behind pipe) by 163%, to 5.5 MMbo and 8.7 Bcfg (6.90 Mmboe) from June 2021. Also, importantly we achieved a 250% production replacement in our PDP reserves.

Byron has funded its 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 also conventional debt funding, which usually carries highly restrictive debt covenants and extensive hedging requirements.

Byron intends to continue is strategy of adding to the Proved Developed Reserves by drilling on its SM58 area leases in the shallow water in the Gulf of Mexico where we have mapped extensive Undeveloped Reserves and Prospective Resources in a number of prospects.

As in previous years, I want to thank our management team, employees and contractors who have worked very hard in challenging circumstances. I would also like to 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

Introduction

During the year ended 30 June 2022, elevated oil and gas prices provided a favourable background to the Company's operations in the shallow waters of the Gulf of Mexico, Offshore Louisiana, USA.

Byron's ability to maintain operations at the SM71 F and SM58 G platforms in the Gulf of Mexico was not impacted by COVID-19 during the year ended 30 June 2022.

Byron's office in Lafayette, Louisiana, worked in line with recommendations of Louisiana State, and Byron's Australia-based team worked as advised by the Australian government(s), to comply with COVID-19 regulations. Byron's offshore contractors have continued to work within the Louisiana State's and the Bureau of Safety and Environmental Enforcement's guidelines.

Production for the year ended 30 June 2022 was approximately 517,000 bbls of oil and over 2.0 bcf of gas, net to Byron, generating net sales revenue of US$53.2 million.

Net Proved Developed Reserves (producing and behind pipe)

Increased 163%, to 5.5 MMbo and 8.7 Bcfg (6.90 Mmboe) as at 30 June 2022 compared to 2021

Net Proved Reserves (1P)

9.6 MMbo and 21.7 Bcfg, (13.2 MMboe)

Net Proved and Probable Reserves (2P)

13.8 MMbo and 28.7 Bcfg (18.6 MMboe)

Annual oil and gas production

Up by 14.0% to 517 mbo net to Byron while gas production declined by 50% to 2,300,000 mmbtu

Net revenue

Up by 49% to US$53.2 million

Production (sales)(net to Byron)	Year ended 30 June 2022	Year ended 30 June 2021
Total net production (NRI basis)		
Oil (bbls)	**516,734**	453,098
Gas (mmbtu)	**2,299,907**	4,603,897
Net revenue after royalties and oil transportation charges (US$ million)	**53.2**	35.7
Realised oil price before transport charges (US$/bbl)	**83.38**	54.05
Realised gas price before transport charges (US$/mmbtu)	**5.41**	2.91

Byron's Proved Reserves (1P) were 9.6 Mmbbl of oil and 21.7 Bcf of gas as at 30 June 2022 and Proved and Probable Reserves (2P) were 13.8 Mmbbl of oil and 28.8 Bcf of gas.

Net remaining reserves as at 30/6/2022	Oil (Mmbo)	Gas (Bcf)	Mmboe (6:1)
Proved	**9.6**	**21.7**	**13.2**
Probable	4.2	7.1	5.4
Proved and Probable (2P)	**13.8**	**28.8**	**18.6**
Possible	4.2	5.1	5.1
Proved, Probable and Possible (3P)	**18.0**	**33.8**	**23.7**
Prospective Resources	**23.9**	**297.4**	**73.5**

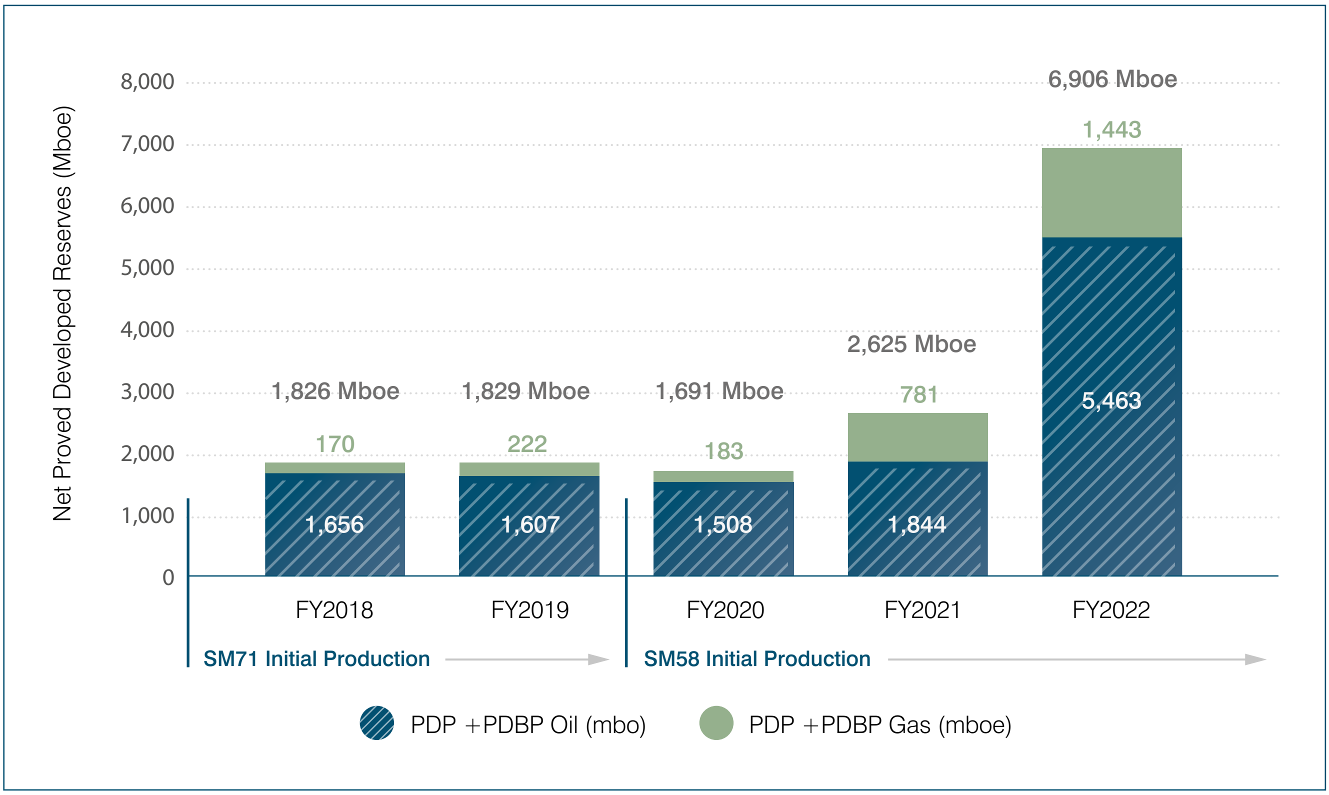
Reserves – The aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation.

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 are required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

Importantly, 6.9 million barrels of oil equivalent ("Mmboe") reserves (net) were in the Proved Developed category out of a total of 13.2 Mmboe as at 30 June 2022.

Byron Energy Net Proved Developed Reserves as at 30 June 2022

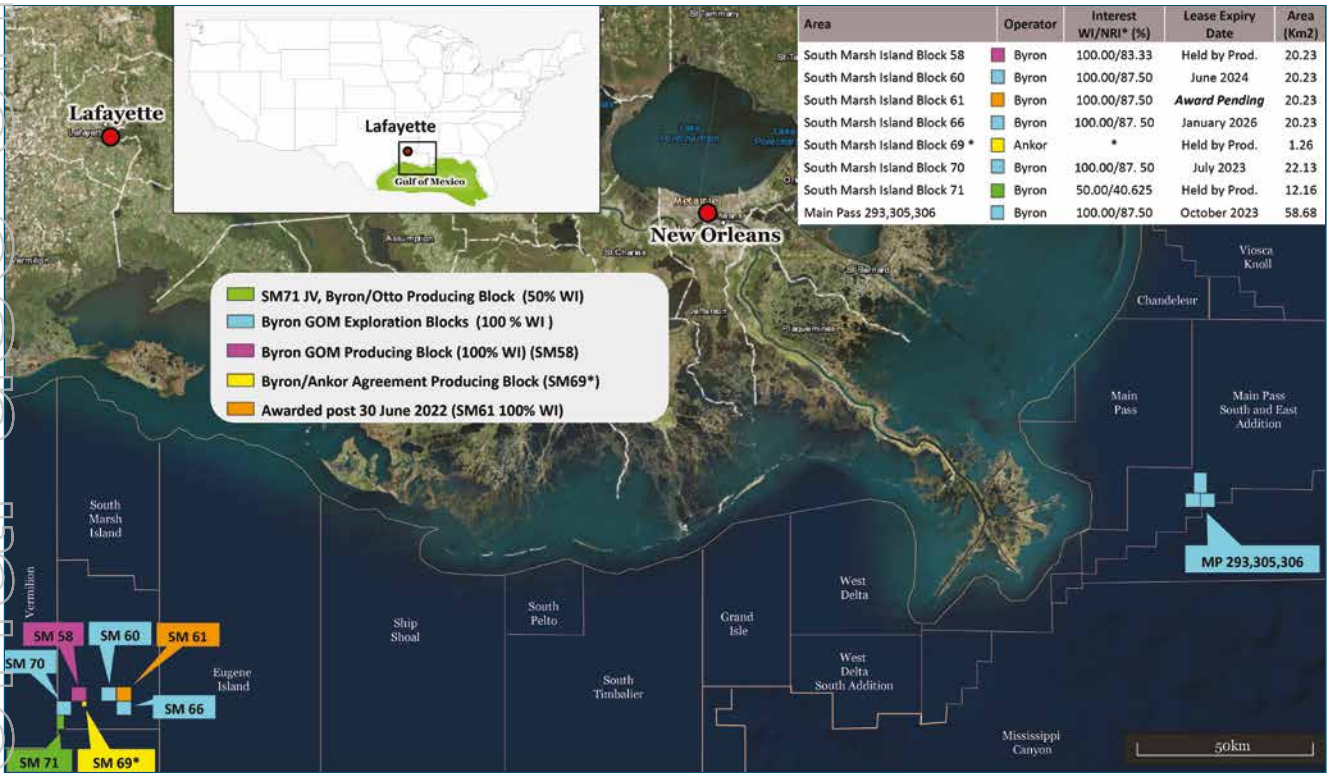


Total Proved Developed Reserves as at 30 June 2022 increased 163% to 5.5 MMbo and 8.7 Bcfg, equivalent to 6.90 MMboe, from 2.6 MMboe, as at 30 June 2021 reflecting significant actively producing and behind pipe reserves set up for future production. Additions during the 2022 financial year of 4.1 MMbo and 5.5 Bcfg, or 5.0 MMboe to the Total Proved Developed Reserves are attributable to the drilling of the E2, G3, and G5 wells.

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 30 June 2022



Area	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km2)
South Marsh Island Block 58	Byron	100.00/83.33	Held by Prod.	20.23
South Marsh Island Block 60	Byron	100.00/87.50	June 2024	20.23
South Marsh Island Block 61	Byron	100.00/87.50	***Award Pending***	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 70	Byron	100.00/87. 50	July 2023	22.13
South Marsh Island Block 71	Byron	50.00/40.625	Held by Prod.	12.16
Main Pass 293,305,306	Byron	100.00/87.50	October 2023	58.68

* SM58 E1 WI53.00%/NRI 44.167%; WI 100%/NRI 80.33% pre payout; post payout NRI 77.55 or 58.33% 58.33% depending on election by W&T Offshore, Inc.

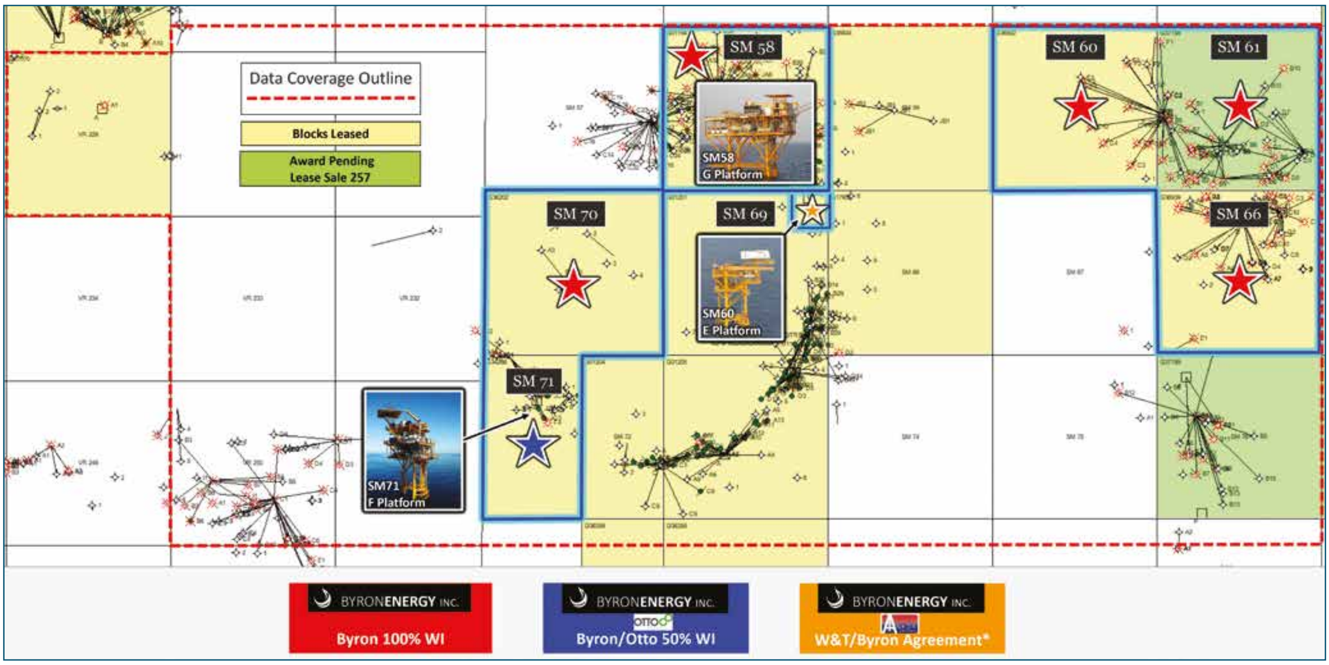
1. South Marsh Island 73 Salt Dome

The South Marsh Island 73 Field (SM73 Field) encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 Field. The SM73 Field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 feet to 8,800 feet Total Vertical Depth. The majority of the field production has come from depths less than 7,500 feet in high quality sandstone reservoirs.

Byron is the operator and 100% working interest holder in six areas of interest around the SM73 Field, comprising SM58/60/61/66/70 and north east portion of SM69, as shown in the map below. Byron is also the operator of SM71, where it has a 50% working interest.

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 Marsh Island Leases and RTM Data Coverage Area



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

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

Water depth in the area is approximately 137 feet.

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

The F1 and F3 wells are producing in the primary D5 Sand reservoir, the F2 well is producing from the J1 Sand and F4 is also producing from the J1 Sand.

As of 30 June 2022, the SM71 F facility has produced approximately 4.1 million barrels of oil (Mmbo) (gross) since initial production began. The facility has also produced approximately 5.1 billion cubic feet of gas (Bcfg) (gross).

During the year ended 30 June 2022, Byron received all relevant approvals for the F2 recompletion.

Review of Operations continued

In addition, Byron received permits to perform remedial work in the SM71 F4 well, which is a 100% working interest Byron well, to reperforate the J1 Sand to establish a better oil rate after work on the well was initiated in late 2021. That result was hindered by a poor cement isolation packer that resulted in the plugging of the perforations.

Both jobs were completed with a lift-boat in mid-August 2022, with production from the J1 Sand recompletion in the SM71 F2 initiated on 31 August 2022.

The SM71 F4 well was also recompleted to the J1 Sand and brought online in September 2022. However, flowing tubing pressure data indicated that the well may still have near wellbore damage from the initial J1 Sand recompletion in October 2021.

South Marsh Island 71 (SM71) Project Summary

Working Interest Holders	Byron Energy 50% (Operator) *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 and F3	F2 November 2017, 205 TVT NFO F3 January 2018 , 175 TVT NFO
Initial Production (Three Wells) F1, F2, F3	F1 first prod. March 2018 F2 and F3 first prod. April 2018
Total Gross Project Oil and Gas Produced from March 2018 to June 2022	4.1 mmbo + 5.1 Bcf
Net 2P Remaining Reserves*	3.0 mmbo + 2.2 bcf

SM71 Reserve Summary*	Gross Reserves Remaining 30/6/22		Net Reserves Remaining 30/6/22	
	mbo	MMcf	mbo	MMcf
1P Proved	**4,547**	**2,864**	**1,862**	**1,171**
Probable	2,739	2,394	1,131	982
2P	**7,286**	**5,258**	**2,993**	**2,153**
Possible	2,642	1,912	1,081	781
3P	**9,928**	**7,170**	**4,074**	**2,934**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**2,406**	**48,948**	**977**	**19,885**

* Collarini and Associates reserves report as at 30 June 2022; refer ASX release 14 September 2022.

To increase operational efficiency and reduce cost, the G3 and G5 wells were batch drilled by driving conductor pipe for each well, then drilling and cementing surface casing in each well before drilling the target sections in each well.

Byron's share of SM71 production and sales for the year 30 June 2022 is shown in the table below.

Production (sales)	Year ended 30 June 2022	Year ended 30 June 2021
Gross production		
Oil (bbls)	**783,716**	893,653
Gas (mmbtu)	**660,806**	851,143
Byron share of gross production (WI basis)		
Oil (bbls)	**392,742**	448,917
Gas (mmbtu)	**334,639**	490,873
Net production (Byron share (NRI basis)		
Oil (bbls)	**319,103**	364,748
Gas (mmbtu)	**271,894**	398,894

Oil production for the year ended 30 June 2022 was below the volumes achieved for the 2021 year mainly due to natural decline, platform shut-ins necessitated by named windstorms and downtime arising from shut-ins as a result of a leak in the third-party oil sales pipeline.

Byron's share of net revenue, after royalties, oil transportation charges and other customary price adjustment, for the 2022 year from SM71 of US$24.4 million was 28% above US$19.0 million for the 2021 year, due to higher realised oil and gas prices partly offset by lower sales volumes. Lease operating expenses, excluding amortisation and depreciation, for the 2022 year were US$2.4 million.

As of 30 June 2022, Collarini has assigned proved reserves (net to Byron) of 1.9 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 has also earned a 100% WI in the SM69 E2 well ("E2") under the Joint Exploration Agreement (JEA) with ANKOR group (ANKOR), subsequently acquired by W&T Offshore, Inc. (W&T Offshore) during the March 2022 quarter), which provided for the drilling of the E2 exploration well operated by Byron. By funding 100% of the E2 well, Byron earned 100% WI and 80.33% NRI until E2 Project Payout, at which time, and at W&T Offshore's election, Byron's NRI will either adjust to 77.33% or W&T Offshore can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI.

Water depth in the area is approximately 132 feet.

As of 30 June 2022, the SM58 G facility has produced approximately 6.8 Bcfg and 0.3 Mmbo of oil and condensate (gross) on a cumulative basis from three wells (G1, commenced production in September 2020, G2, commenced production in October 2020 and E2, commenced production on 21 October 2021).

The SM58 G1 well produces from the Upper O Sand and producing 56.5-degree gravity condensate and no formation water. Gas and oil production from the G1 well have continued to follow a natural and predictable pressure decline.

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

Production from the Company's E2 well began on 21 October 2021. Production of oil, gas and any other liquids from the E2, located on SM69 E platform, flows to the Byron operated SM58 G platform where separation occurs before oil and gas are sent to sales pipelines. Unlike the E1 well production, E2 production is not subject to any third-party processing fees.

During the year ended 30 June 2022, Byron drilled and completed two wells from the SM58 G Platform, comprising the G3 well, drilling the Rainbow Trout prospect, and the G5 well, drilling the Smoked Trout prospect.

To increase operational efficiency and reduce cost, the G3 and G5 wells were batch drilled by driving conductor pipe for each well, then drilling and cementing surface casing in each well before drilling the target sections in each well.

The G3 reached total depth of 8,642' Measured Depth (MD)/6,970' True Vertical Depth (TVD) on 13 May 2022 (USCDT). Real Time Log While Drilling (LWD) tools identified hydrocarbons, most likely oil, based on the LWD and mudlog response in both the primary J Sand interval and the secondary K4/B65 Sand (K4) interval. A third, higher risk objective, the O Sand, was present as a poorly developed sandy/silty interval with hydrocarbon responses on the logs but is considered uneconomic. Byron did not carry pre-drill reserves or prospective resources for the O Sand in the G3 well.

The primary target J Sand logged 27' TVT net pay. While the J Sand in G3 logged thinner pay than predicted, the J Sand is high quality. The Company completed the J Sand using modern frac pack sand control techniques.

The secondary target K4 Sand logged 31' of TVT net pay, most likely oil, based on the LWD and mudlog response. Like the J Sand, the K4 was completed using modern frac pack sand control measures.

The G3 was completed in the J Sand, after G5 was drilled, and brought into production on 1 August 2022 after clearing an obstruction in the production tubing, and the Enterprise 264 drilling rig was released on 3 August 2022.

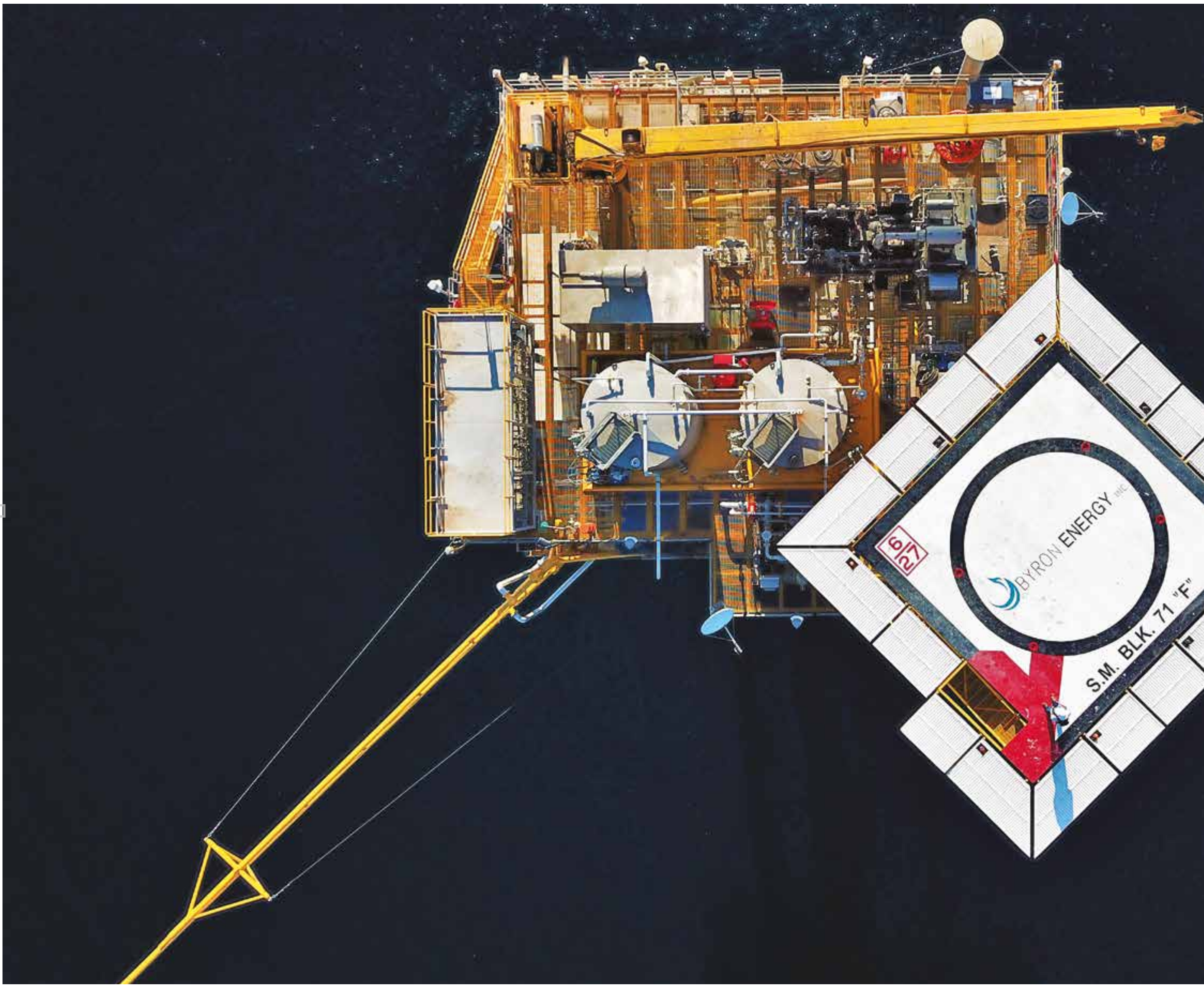
The SM58 G5 well, drilling the Smoked Trout prospect, had been drilled to a depth of 9,650 feet MD 7,672 feet TVD and had logged 81 feet TVT hydrocarbon pay in three sands (most likely oil based on LWD logs and mudlog responses). The I2 Sand, K4/B65 Sand and L2 Sands were cased with 7" production casing after the top drive on the EOD 264 failed and had to be replaced (see ASX Announcements dated 26 May 2002 and 2 June 2022 for additional information).

Following top drive repairs, drilling operations resumed Sunday, 6 June 2022 and the G5 well reached total depth of 10,228' MD/8,244' TVD on 6 June 2022 (USCDT). Real Time LWD logging tools identified hydrocarbons, most likely oil, based on the log and mudlog responses from the primary N2 Sand interval and a minor, secondary objective, the N4 sand.

The primary target N2 Sand logged 36 feet TVT net pay over a gross interval of 76 feet measured depth. As mapped, the G5 well intersected the N2 Sand in an attic position updip to an accumulation of oil and gas in the N2 Sand that had previously produced 3 million barrels of oil (mmbo) and 5.7 billion cubic feet of gas (bcf) from six wells. Those wells had an average net pay thickness of 31 feet TVT and exhibited a strong water drive reservoir mechanism. The G5 is structurally 1,475 feet high to the best well in the pool, the SM58 B12 well, and potentially establishes a very large column of oil and gas. Connectivity between to G5 and the down dip area will ultimately be determined through production, but the results of the G5 are consistent with Byron's in-house pre-drill mapping and reservoir quality expectations.

The G5 well also logged 11 feet of TVT net pay in the N4 Sand, also most likely oil, based on the LWD and mudlog response. No reserves have been attributed to the N4 Sand and it will be future down hole completion in the G5 after the N2 and L2 Sands are produced.

The SM58 G5 (G5) was completed in the L2 Sand and production began on 13 July 2022.



South Marsh Island 58 Project Summary

Working Interest Holders	Byron Energy 100% (Operator)
Operator	Byron Energy Inc.
Water Depth	~37 meters (121')
Previous SM58 Production	35.8 mmbo + 265 Bcf
Acquired 1 Jan 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 Completed and 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 and Gas Produced from Sept. 2020 to June 2022 (including SM69 E2 well)	6.8 BCf and 300,000 bbls
G Platform Capacity	8,000 bopd + 80 mmcfgpd + 8,000 bwpd
Net 2P Remaining Reserves SM58 (excluding E2 well)	9,498 mbo + 25,326 mmcf**

SM58 (excluding SM69 E2 well) Reserve Summary#	Gross Reserves Remaining 30/6/22**		Net Reserves Remaining 30/6/22**	
	mbo	MMcf	mbo	MMcf
1P Proved	**7,715**	**23,105**	**6,428**	**19,254**
Probable	3,686	7,286	3.070	6,072
2P	**11,401**	**30,391**	**9,498**	**25,326**
Possible	3,760	5,201	3,133	4,334
3P	**15,161**	**35,592**	**12,631**	**29,660**
	Gross Prospective Resource		Net Prospective Resource	
Prospective	**20,273**	**42,685**	**16,894**	**35,571**

* By funding 100% of the E2 well Byron earned 100% WI and 80.33% NRI until E2 Project Payout, at which time and at W&T Offshore, Inc's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI. Production from the E2 well located on SM69 E Platform flows to the SM58 G Platform for processing.

** Excludes SM58 E1 and SM69 net 2P remaining reserves of 1.3 mmbl and 1.2 bcf (refer to page 14).

Collarini and Associates reserves report as at 30 June 2022; refer ASX release 14/9/2022.

Byron's share of SM58 production (including SM69 E2 well) for the year ended 30 June 2022 is shown in the table below.

Production (sales)	Year ended 30 June 2022	Year ended 30 June 2021
Gross production		
Oil (bbls)	**220,078**	85,873
Gas (mmbtu)	**2,432,082**	5,043,006
Byron share of gross production (WI basis)		
Oil (bbls)	**220,078**	85,873
Gas (mmbtu)	**2,432,082**	5,043,006
Net production (Byron share (NRI basis)		
Oil (bbls)	**178,183**	71,558
Gas (mmbtu)	**2,024,505**	4,202,475

Oil production for the year ended 30 June 2022 was above the volumes achieved for the 2021 year mainly due to inclusion of the E2 well production during 2021. Gas production was down due to natural decline at the G1 well, platform shut-ins necessitated by named windstorms and downtime arising from shut-ins as a result of a leak in the third-party oil sales pipeline and the drilling of G3 and G4 wells.

For the year ended 30 June 2022, Byron's share of net revenue from SM58 after royalties, oil transportation charges and other customary price adjustments was US$27.1 million compared to US$15.9 million for the 2021 year, due to higher realised oil and gas prices and higher oil production partly offset by lower gas sales volumes. Lease operating expenses, excluding depreciation and amortisation, were US$4.2 million for the 2022 year.

As of 30 June 2022, Collarini has assigned proved reserves (net to Byron) of 6.4 Mmbo and 19.3 Bcf.

Collarini has also assigned 2P reserves (net to Byron) of 9.5 Mmbol and 25.3 Bcf to SM58 as at 30 June 2022. In comparison, 2P reserves (net to Byron) as at 30 June 2021 were 5.2 Mmbbo and 20.5 Bcf. The increase in 2P reserves is primarily due to the drilling of the G3, and G5 partly offset by 2022 production.

Collarini assigned 3.1 Mmbbo and 4.3 Bcf (net to Byron) in possible reserves and aggregate net Prospective Resources of 16.9 Mmbbo and 35.6 Bcf to SM58.

(c) SM58 E1/69 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 S ½ of the SE ¼ of the SE ¼ of SM58, as well as a 53% working interest in the SM69 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 SM58 E1 well and E platform, which is located in the NE corner of the SM69 block.

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).

While the SM69 E2 well (referred to above) is located on the SM69 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 SM58 E1 and SM69 Project Summary

Working Interest Holders	Byron Energy
Operator SM69 E2 well Operator SM58 E1/SM69 E Platform	Byron Energy Inc. W&T Offshore (ANKOR)
Water Depth	38 meters (125')
Previous SM58 Production (Fault Block A)	3.4 mmbo + 4.3 bcf
Acquired SM58 E1/SM69 E Platform 1 Jan 2019 from Fieldwood Energy	US$4.25 million
Farmed into SM69 E2 via JEA with ANKOR	100% WI/83.33% NRI for funding 100% of SM69 E2 well
Byron SM69 E2 discovery well	September 2021, 81' TVT Hydrocarbon Pay
SM58 G Platform Installation Completed and Installed	July 2020 (SM69 E2 well produced back to SM58 G platform through pipeline laid in July 2020)
Initial production SM69 E2	Commenced on 21 October 2021 (processed on SM58 G Platform)
Net 2P Remaining Reserves SM58 E1 and SM69*	1,330 mbo + 1,239 mmcf

SM58 E1/SM69 Reserve Summary	Gross Reserves Remaining 30/6/22		Net Reserves Remaining 30/6/22#	
	mbo	MMcf	mbo	MMcf
1P Proved	**2,504**	**2,572**	**1,304**	**1,233**
Probable	59	13	26	5
2P	**2,563**	**2,585**	**1,330**	**1,239**
Possible	-	-	-	-
3P	**2,563**	**2,585**	**1,330**	**1,239**
	Gross Prospective Resources		Net Prospective Resources	
Prospective	**856**	**857**	**548**	**548**

* Collarini and Associates reserves report as at 30 June 2022; refer ASX releases 14/9/2022.

\# By funding 100% of the E2 well Byron earned 100% WI and 80.33% NRI until E2 Project Payout, at which time and at W&T Offshore, Inc's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI. Production from the E2 well located on SM69 E Platform flows to the SM58 G Platform for processing.

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Byron's share of production from the SM58 E1 well for the year ended 30 June 2022 is shown in the table below.

Production (sales)	Year ended 30 June 2022	Year ended 30 June 2021
Gross production		
Oil (bbls)	**44,033**	38,018
Gas (mmbtu)	**7,943**	5,858
Byron share of Gross production (53% WI)		
Oil (bbls)	**23,337**	20,149
Gas (mmbtu)	**4,210**	3,015
Net production (Byron share 44.167% (after royalty))		
Oil (bbls)	**19,448**	16,791
Gas (mmbtu)	**3,508**	2,588

Oil and gas production for the year ended 30 June 2022 was slightly above the volumes achieved for the 2021.

For the year ended 30 June 2022, Byron's share of net revenue from SM58 E1 well was approximately US$1.7 million compared to US$0.9 million for the 2021 year, mainly due to higher realised oil and gas prices and higher production.

Collarini has assigned 2P reserves (net to Byron) of 1.3 Mmbo and 1.2 Bcf to the SM58 E1 (in S ½ of SE ¼ of SE ¼ of SM58) and the SM69 E2 (NE ¼ of NE ¼ of SM69).

(d) South Marsh Island Exploration and Evaluation Assets

South Marsh Island 60

Byron holds a 100% WI and 87.5% NRI in SM60, in close proximity to Byron's SM58 platform. Water depth in the area is approximately 125 feet.

The SM60 block was part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

Byron acquired the SM60 lease in 2019 and as a result of extensive mapping has advanced two prospects to drill ready status and determined that prospects previously identified on SM59 extend updip on to SM60, the most likely location for drilling.

Collarini has assigned aggregate net Prospective Resources of 2.3 Mmbbl and 209 Bcf to SM60.

South Marsh Island 70

Byron has a 100% WI and 87.5% NRI (royalty rate of 12.5%) South Marsh Island 70 ("SM70") at the Gulf of Mexico OCS Lease Sale 250 held on 21 March 2018 in New Orleans, Louisiana.

Byron has identified several higher risk exploratory leads on SM70. These leads are being evaluated following completion of Byron's South Marsh Island project seismic reprocessing work in late 2018.

Collarini has assigned aggregate net Prospective Resources of 3.2 Mmbbl and 32.6 Bcf to SM70.

South Marsh Island 66

Byron holds a 100% WI and an 87.50% NRI in SM66. This lease is 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.

The SM66 block was part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

Main Pass 306

Byron currently holds a 100% WI and an 87.50% NRI in Main Pass 293, 305 and 306 ("MP306 Field") acquired at the Gulf of Mexico, Outer Continental Shelf ("OCS") Lease Sale 251 ("Lease Sale 251") held in New Orleans, Louisiana on 15 August 2018.

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

MP306 is a structurally and stratigraphically complex salt dome which should lend itself to advanced RTM interpretation techniques as employed at Byron's SM58 salt dome project. These leases were acquired at the Gulf of Mexico, Outer Continental Shelf Lease Sale 251 held on 15 August 2018.

During the year ended 30 June 2022, Byron licensed 3D Reverse Time Migration (RTM) seismic data that was reprocessed by the contractor (TGS) in 2022 and has begun interpretation. MP306 was discovered in 1969 and lies in approximately 200 feet of water. Byron's licensed data area allows the integration of all producing wells on the MP306 salt dome and also ties recent discoveries in the adjacent area, which may serve as analogues for any generated prospects. Byron's technical team has begun the interpretation project and the work is ongoing.

Portfolio Optimisation

South Marsh Island Area

With Byron's South Marsh Island 57 lease ("SM57") due to expire in June 2022, Byron took the opportunity to optimise its portfolio of exploration opportunities and relinquish SM57 in October 2021 and replace it with South Marsh Island 61 lease ("SM61"). SM57 did not have any 3P reserves attributed to it.

Byron was the apparent high bidder on SM61, the only bid placed by the Company at the Gulf of Mexico, Outer Continental Shelf (OCS) Lease Sale 257 held in New Orleans, Louisiana, on Wednesday, 17 November 2021.

SM61 lies within the area of Byron's RTM reprocessing project, which was used to evaluate the prospect potential on the block.

The award of SM61 by the BOEM was held up by court challenges after the U.S. District Court for the District of Columbia (D.C. District Court, on 27 January 2022, vacated the results of Lease Sale 257.

More recently, President Joe Biden signed the *Inflation Reduction Act (IRA) of 2022* into law on 16 August 2022. The IRA requires the U.S. Department of the Interior (Interior) to award Lease Sale 257 leases to the highest bidders.

Subsequent to 30 June 2022, in mid-September 2022, Byron was awarded SM61 by the BOEM.

The SM61 lease maintains Byron's prospect inventory and our footprint in the blocks encompassing the SM73 salt dome, in the shallow waters of the GOM, while extending the average lease maturity date.

Eugene Island Area

Byron acquired leases over Eugene Island blocks 62, 63, 76 and 77 (EI77) in 2018 based on 2015 legacy RTM processed 3D seismic data. In 2018, Byron undertook a proprietary RTM reprocessing project with WesternGeco, a Schlumberger Company, using the same processing workflow that was applied to Byron's South Marsh Island 58/71 project. Once this data was delivered in late 2019, an extensive subsurface remapping project was undertaken that was recently completed. The 2019 reprocessing resulted in a major data quality uplift and after full evaluation it has been determined that several previously identified development attic opportunities did not meet the Company's technical and economic risk criteria. It was also determined that the previously identified deep exploratory concepts did not meet certain geological and geophysical criteria and were judged to be too high risk to warrant drilling. Also, the EI77 leases are in very shallow water depths (less than 25 feet) and there is only one jackup rig currently operating in the GOM able to access a drilling location in that water depth. That rig is on long-term contract to another operator and hence unavailable. Thus, on a technical, economic and practical basis, Byron elected to relinquish all four leases in June 2022, prior to the full lease term.

Properties

As at 30 June 2022, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico and coastal marshlands of Louisiana, USA, comprised:

Properties	Operator	Interest WI/NRI (%)*	Lease Expiry Date	Lease Area (Km^2)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 60	Byron	100.00/87.50	June 2024	20.23
Block 61#	Byron	100.00/87.50	September 2027	21.23
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, Inc	53.00/44.16667		
SM69 (NE ¼ of NE ¼ E2 well)	Byron	100.00/77.33-80.33***	Production	1.3
Block 66	Byron	100.00/87.50	December 2025	20.23
Block 70	Byron	100.00/87.50	July 2023	22.13
Main Pass				
Block 293	Byron	100.00/87.50	October 2023	18.46
Block 305	Byron	100.00/87.50	October 2023	20.23
Block 306	Byron	100.00/87.50	October 2023	20.23

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

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

*** By funding 100% of the E2 well, Byron earned 100% WI and 80.33% NRI until E2 Project Payout, at which time and at W&T Offshore, Inc's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI.

Awarded to Byron in September 2022.

Reserves and Resources

The Company's reserves and resources estimate as at 30 June 2022 was released to the ASX on 14 September 2022 and is summarised below.

- **Proved Reserves (1P): 9.6 Mmbbl of oil and 21.7 Bcf of gas**
- **Proved and Probable Reserves (2P): 13.8 Mmbbl of oil and 28.7 Bcf of gas**
- **Proved, Probable and Possible Reserves (3P): 18.0 Mmbbl of oil and 33.8 Bcf of gas**
- **Prospective Resources: 23.9 Mmbbl of oil and 297.4 Bcf of gas**

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

Remaining as at 30 June 2022 (net to Byron)	Category	Oil Mbbl	Gas MMcf	Mboe (6:1)
Reserves (developed and undeveloped)				
Proved Developed Producing (including shut-in @30.6.22)	PDP*	2,677	4,397	3,410
Proved Developed Behind Pipe	PDBP	2,784	4,260	3,494
Total Proved Developed	**PD**	**5,461**	**8,657**	**6,904**
Total Proved Undeveloped	PUD	4,132	13,000	6,299
Total Proved	**1P**	**9,593**	**21,657**	**13,204**
Total Probable Reserves		4,228	7,060	5,405
Total Proved and Probable	**2P**	**13,821**	**28,717**	**18,609**
Total Possible Reserves		4,214	5,115	5,066
Total Proved, Probable and Possible	**3P**	**18,035**	**33,832**	**23,675**
Total Prospective Resources				
Best Estimate (unrisked)	**PR**	**23,931**	**297,434**	**73,503**

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 are required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

The following table shows a split of Byron's remaining reserves, as at 30 June 2022, into developed and undeveloped categories by project and by product. All of the projects 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
30 June 2022	**Oil Mbbl**	**Gas MMcf**	**Oil Mbbl**	**Gas MMcf**	**Boe Mboe (6:1)**
Total					
Proved (1P)	**5,462**	**8,656**	**4,132**	**13,001**	**13,203**
Probable Reserves	1,371	1,644	2,857	5,416	5,405
Proved and Probable (2P)	**6,833**	**10,300**	**6,989**	**18,417**	**18,608**
Possible	1,079	1,318	3,135	3,797	5,066
Proved, Probable and Possible (3P)	**7,912**	**11,618**	**10,124**	**22,214**	**23,674**

The following table reconciles the movement in Byron's reserves between 30 June 2021 and 30 June 2022.

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

	Oil (Mbbl)(Net to Byron)					Gas (MMcf)(Net to Byron)				
Reserves Reconciliation	**Remaining 30/6/2021**	**Production 2022**	**Additions and Revisions 2022**	**Relinq-uishments 2022**	**Remaining 30/6/2022**	**Remaining 30/6/2021**	**Production 2022**	**Additions and Revisions 2022**	**Relinq-uishments 2022**	**Remaining 30/6/2022**
Proved (1P)	**8,715**	**-512**	**2,132**	**-741**	**9,594**	**55,063**	**-2,088**	**973**	**-32,291**	**21,657**
Probable Reserves	5,427	0	-63	-1,136	4,228	42,406	0	259	-35,605	7,060
Proved and Probable (2P)	**14,142**	**-512**	**2,069**	**-1,877**	**13,822**	**97,469**	**-2,088**	**1,232**	**-67,896**	**28,717**
Possible Reserves	8,606	0	-1,760	-2,632	4,214	25,853	0	-2,032	-18,706	5,115
Proved, Probable and Possible (3P)	**22,748**	**-512**	**309**	**-4,509**	**18,036**	**123,322**	**-2,088**	**-800**	**-86,602**	**33,832**

Material Changes to Reserves

- 2022 positive reserve movements were dominated by the conversion of undeveloped reserves and resources to Developed Reserves as the Company focused on development operations in the SM58 area.
- Total Proved Remaining was reduced by the 2022 production of 512,000 barrels of oil and 2.09 Bcf of gas net to Byron, through 30 June 2022 from the Byron operated SM71 F and SM58 G platforms and the SM58 E1 well, as well as from undrilled relinquished acreage.
- Relinquishment of EI77 leases resulted in a net decrease of 32.3 Bcfg and 0.74 MMbo of Proved Undeveloped Reserves. These undeveloped reserves were partially offset by the addition of 0.75 MMbo and 1.0 Bcfg of Proved Reserves related to the SM58 River Trout prospect. The combined impact of relinquishing these undrilled leases resulted in a reduction of Companywide total Proved and Probable Reserves.

Prospective Resource as at 30 June 2022

The following table shows Byron's prospective resources as at 30 June 2022 compared to 30 June 2021.

Byron Energy Limited Prospective Resources (net to Byron)

Gulf of Mexico, offshore Louisiana, USA

Best Estimate Unrisked 30 June 2022	Oil Mbbl	Gas MMcf	Mboe (6:1)
SM71	977	19,885	4,291
SM58	16,894	35,571	22,823
SM58 E1/SM69	548	548	639
SM60	2,341	208,835	37,147
SM70	3,171	32,595	8,604
Total Prospective Resources (2022)	**23,931**	**297,434**	**73,504**
Total Prospective Resources (2021)	**33,341**	**572,198**	**128,707**

Material Changes to Prospective Resources

- SM70 Golden Trout prospect added to prospective resource in 2022; and
- SM57 removed from prospective resources (lease relinquished, as reported to the ASX on 18 November 2021); and EI77 removed from prospective resources (lease relinquished, as reported to the ASX on 7 July 2022).

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 an independent petroleum engineering consulting firm that has been providing petroleum consulting services in the USA for more than 15 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 represent, 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 judgement 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. The 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 are 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 18 July 2022, NYMEX West Texas Intermediate (WTI) Strip prices starting on 1 July 2022, of $104.76 per barrel. Beginning 1 January 2023, the Reuters Poll consensus pricing was used with a starting price of $92.19 per barrel and with a final price of $80.23 per barrel on 1 January 2026, then held constant thereafter. Gas prices used in this report represent a Henry Hub base 18 July NYMEX Strip prices starting on 1 July 2022, of $7.427 per MMBtu. Beginning 1 January 2023, the Reuters Poll consensus pricing was used with a starting price of $4.700 per MMBtu, declining to $4.000 per MMBtu on 1 January 2024, 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 2022 (Listing Rule (LR) 5.25.1).

(ii) The reserves and prospective resources in this document have been estimated and are 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 have 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 and 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 are 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 2022

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 2022.

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 18 March 2013

Doug is a petroleum geologist with over 40 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 18 March 2013

Maynard is a geophysicist with over 30 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 18 March 2013

Prent is a geoscientist with over 30 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 125 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 10 successful wells in 12 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 18 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 30 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. 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 18 March 2013

Paul has been in merchant banking for more than 35 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 and a Fellow of the Australian Institute of Company Directors.

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.

William R Sack
Executive Director
Appointed 3 October 2014

Bill is an explorationist with more than 30 years' experience in the Gulf of Mexico region in technical, commercial and executive roles. He was appointed to the Board of Directors on 3 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 80 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 2022, 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 2022, the Company issued 41,100,000 fully paid ordinary shares upon conversion of 41,100,000 share options. The 41,100,000 ordinary shares were issued on 7 January 2022. The Company issued 2,000,000 share options on 11 January 2022 to staff at an exercise price of A$0.16 cents per share with an expiry date of 31 December 2024.

Post 30 June 2022, no other ordinary shares, or share options were issued and no share options were exercised subsequent to 30 June 2022 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 Battersby	57,300,568	0	N/A	N/A
M Smith	49,047,991	0	N/A	N/A
P Kallenberger	12,808,762	0	N/A	N/A
C Sands	24,710,783	0	N/A	N/A
P Young	27,446,619	0	N/A	N/A
W 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 18 March 2013

Nick is a qualified accountant with over 40 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$22,215,308 (2021: US$5,854,375).

Review of operations

Financial summary

The Group recorded a net profit after income tax of US$22,215,308 for the year ended 30 June 2022, compared to a net profit of US$5,854,375 for the year ended 30 June 2021.

Earnings before interest, tax, amortisation, share-based payments, impairment, realised oil hedge price losses and depreciation and exploration expense ("EBIDAX") for the year ended 30 June 2022 totalled US$41,576,783, an increase of 73% compared to US$24,046,044 for the year ended 30 June 2021, primarily as a result of higher realised oil and gas prices and higher oil production partly offset by lower gas production.

EBITDAX (US$)	Year ended 30 June 2022	Year ended 30 June 2021
Profit for the year from continuing operations	**22,215,308**	5,854,375
Net financial expenses	**2,134,651**	3,427,738
Depreciation and amortisation	**12,063,092**	13,798,246
Share-based payments	**1,599,464**	–
Impairment expense and dry hole expense	**3,082,807**	595,951
Realised loss on forward commodity price contracts	**481,461**	369,734
EBITDAX	**41,576,783**	24,046,044

Production, Prices and Revenue

Net production (sales) for the year ended 30 June 2022 was 516,734 barrels of oil and 2,299,907 mmbtu of gas compared to 453,098 barrels of oil and 4,603,897 mmbtu of gas for the year ended 30 June 2021. The increase in oil production was due to commencement of production from the SM69 E2 well in October 2021. The decrease in gas production was mainly due to lower gas production from the SM58 G1 well. Production for the year ended 30 June 2022 was impacted by Hurricane Ida, which resulted in 14 days of production being lost in August 2021, shut-ins during the June 2022 quarter resulting from a leak in third party oil pipeline, and shut-ins of the SM58 platform in the June quarter 2022 for drilling of wells from SM58 platform.

For the year ended 30 June 2022, Byron realised an average crude oil sales price of US$78.81 per barrel (after transportation and quality adjustments) and an average realised gas price of US$5.05 (after transportation and quality adjustments), an increase of approximately 59% and 97% respectively compared to the year ended 30 June 2021, where average prices of US$49.50 per barrel of oil and US2.56 per mmbtu were realised.

Net revenue (after royalties) for the year ended 30 June 2022 of US$53,143,411 was approximately 48% above US$35,837,228 for the year ended 30 June 2021. The increase in the 2022 year was driven primarily by increased realised oil and gas prices and higher oil production partly offset by lower gas production.

Byron's share of oil and gas production and sales by field for the 30 June 2022 year, compared to the corresponding period in 2021 is summarised in the table below.

Production (sales)	Year ended 30 June 2022	Year ended 30 June 2021
Net production Byron share (NRI basis) SM71		
Oil (bbls)	**319,103**	364,748
Gas (mmbtu)	**271,894**	398,834
Net production Byron share (NRI basis) SM58		
Oil (bbls)	**178,183**	71,558
Gas (mmbtu)	**2,024,505**	4,202,475
Net production Byron share (NRI basis) SM58 E1 well		
Oil (bbls)	**19,448**	16,791
Gas (mmbtu)	**3,508**	2,588
Total net production (NRI basis)		
Oil (bbls)	**516,734**	453,097
Gas (mmbtu)	**2,299,907**	4,603,897

Cost of sales

Cost of sales, which includes base lease operating expenses, insurance premiums, amortisation and depreciation and gas transportation charges, were US$19,105,413 for the year ended 30 June 2022 compared to US$20,793,128 for the comparable period in 2021. The decrease is primarily due to lower amortisation charges and lower gas transportation costs reflecting lower gas production partly offset by higher lease operating expenses and insurance premiums.

Corporate and administration costs

Corporate and administration costs were US$2,920,851 for the year ended 30 June 2022, compared to US$2,547,239 for the year ended 30 June 2021, mainly due to increased remuneration expense reflecting an increase in salaries effective 1 January 2022 and increased staff numbers.

Impairment charges

Impairment charges of US$3,082,807 for the year ended 30 June 2022 were higher in comparison to the year ended 30 June 2021 of US$595,951 due to the write off of four Eugene Island blocks upon relinquishment in June 2022 and relinquishment of South Marsh Island 57 in October 2021, compared to residual costs of South Marsh Island 74, Bivouac Peak and write down of the South Marsh Island 59 lease in June 2021 to $0, prior to its relinquishment in the 2022 financial year.

Financial expense

Financial expense of US$2,267,466 for the year ended 30 June 2022 was lower than financial expense of US$3,481,075 in 2021 as a result of lower average loan balances during the 2022 year.

Share-based payment expenses

Share-based payment expenses in the year ended 30 June 2022 were US$1,599,464 compared to nil share-based payment expenses in the 2021 financial year. Share-based payment expenses in the 2022 financial year comprise the expenses in relation to the interest free loans granted and approved by shareholders at the Company's 2021 AGM to executive directors, senior staff and contractors to be used solely for the funding of the conversion of 41,100,000 share options over unissued shares in the Company, which expired on 31 December 2021. The shares were issued on 7 January 2022.

Balance sheet, cash flow and liquidity

At 30 June 2022, the consolidated entity had total assets of US$151,045,468 (30 June 2021: US$114,832,843) and total liabilities of US$45,533,876 (30 June 2021: US$33,599,978) resulting in net assets of US$105,511,592 (30 June 2021: US$81,232,865). The increase in net assets was primarily due to an increase in the written down value of the oil and gas properties (drilling and completion of the SM69 E2 well and drilling of SM58 G3 and G5 wells), higher cash and cash equivalents and higher trade debtors partly offset by higher trade and other payables and a reduction in the carrying value of exploration and evaluations assets.

Net cash provided by operating activities for the year ended 30 June 2022 was US$36,612,410 compared to the year ended 30 June 2021 of US$21,352,060, largely due to higher realised oil and gas prices.

At 30 June 2022, the consolidated entity held cash and cash equivalents of US$14,087,032 (30 June 20212 US$4,143,411).

Borrowings at 30 June 2022 were US$20,978,748, primarily comprising prepaid oil revenue, the Crescent Promissory Note and loans from directors and one longstanding shareholder.

Borrowings (US$)	30 June 2022	30 June 2021
Promissory note (Crescent Midstream)	**4,830,114**	15,082,997
Directors and shareholder	**3,446,690**	3,578,780
Insurance premium financing	**1,701,944**	1,530,593
Prepaid oil revenue (unearned revenue)	**11,000,000**	1,750,000
Total	**20,978,748**	21,942,370

The reduction in borrowings is due to repayment of the Crescent Promissory Note in line with the agreement, offset by higher prepaid oil revenues.

During the December 2021 quarter outstanding borrowings from entities associated with Doug Battersby, Maynard Smith, Charles Sands, Paul Young, all directors of the Company, and a longstanding shareholder were extended by 12 months and are now due to be repaid on 31 March 2023.

Prepaid oil revenue (unearned revenue) as at 30 June 2022 was US$11,000,000 compared to US$1,750,000 as at 30 June 2021. The oil revenue prepayment represents amounts received in advance of revenue recognition and is recognised as revenue in future periods when transfer of control to the buyer of Byron's oil production has occurred. The buyer of Byron's oil production and hedging counterparty under the existing forward sale agreement is one of the world's oil supermajors (the "Buyer").

To enhance liquidity, in March 2022 the Buyer provided access to a further funding of US$11.0 million through the prepayment of future oil revenue, drawn down in May 2022. The prepayment has a 12-month repayment term, including a four-month non-repayment grace period, followed by eight equal monthly instalments of US$1.375 million commencing in September 2022. The prepayment is largely secured by Byron's existing forward sale agreement of 400 bopd through to December 2022, plus an additional 200 bopd beginning in January 2023 and ending in March 2023. The fee for this prepayment is approximately US$1 per produced barrel of oil during the one-year term, or until such time as the loan is repaid. The prepayment agreement also includes the provision for an early repayment at the Company's discretion. In addition, in March 2022 Byron executed a three-year extension of its existing oil offtake agreement with the Company's oil purchaser, an oil industry supermajor that has been the sole purchaser of Byron's GOM oil production and hedge counterparty since inception of Byron's production.

Capital expenditure

Capital expenditure for the year ended 30 June 2022 was US$39,730,019, comprising expenditure on oil and gas properties of US$21,253,667, mainly the drilling of SM58 G3 and G5 wells, and exploration and evaluation expenditure of US$18,476,352, mainly the drilling, completion and hook-up of the SM58 E2 well.

Hedging

Byron's realised prices for oil are a combination of hedged and unhedged volumes. The Company's oil hedging position as at 30 June 2022 is governed by a forward sale agreement ("Forward Sale Agreement"), which specifies a price per barrel in advance for each delivery period during the term of the contract.

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

Byron's hedged oil production as at 30 June 2022 is as follows:

Period (Under Forward sale Agreement)	Daily Hedged Volume (bopd)	Period Hedged Volume (bbl)	NYMEX WTI Fixed Base Price Crude Oil*	NYMEX Roll Adjust	LLS/WTI Price Differential	Realised price on hedged production prior to transportation charges
Jul-Dec 2022	400	73,600	US$52.70	unhedged	unhedged	Subject to finalisation
Jan-Mar 2023	200	18,000	US$80.95	unhedged	unhedged	Subject to finalisation

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

COVID-19

Byron's ability to maintain production operations at the SM71 F and SM58 G platforms and drilling operations on the Company's properties in the shallow water of the Gulf of Mexico was not materially impacted by COVID-19 during the year ended 30 June 2022.

Byron's office in Lafayette, Louisiana, continued to work in-line with recommendations of Louisiana State, and Byron's Australian based team worked as advised by the Australian government(s) to comply with COVID-19 regulations.

Byron's offshore contractors have continued to work during the year ended 30 June 2022 within the Louisiana State's and the Bureau of Safety and Environmental Enforcement guidelines.

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 2022 from all wells on the SM71 F Platform totalled approximately 319,103 barrels of oil and 271,894 mmbtu of gas (June 2021 year 364,748 barrels and 398,834 mmbtu). Lower production for the 2022 financial year is mainly due to natural field decline, production shut-ins due to Hurricane Ida and shut-in as a result of a leak in the third-party oil sales pipeline.

As of 30 June 2022, the SM71 F facility has produced approximately 4.1 million barrels of oil ("Mmbo") (gross) since initial production began in March 2018. The facility has also produced approximately 5.1 billion cubic feet of gas ("Bcfg") (gross).

The F1 and F3 wells, producing in the primary D5 Sand reservoir, contributed most of the production during the 2022 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.

Subsequent to 30 June 2022, a lift boat arrived on location at SM71 F Platform on 7 August 2022 to begin recompletion operations on the SM71 F2 and F4 wells. Both wells were recompleted to the J1 Sand using through tubing sand control techniques utilising coiled tubing equipment.

South Marsh Island 58

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

Byron has also earned a 100% WI in the SM69 E2 well (E2) under the Joint Exploration Agreement ("JEA") with ANKOR group, 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, at which time and at the leaseholder's election, Byron's NRI will either adjust to 77.33% or the leaseholders can convert to a 30% WI and Byron's interest in the project would adjust to 70% WI with an unburdened 58.33% NRI. Water depth in the area is approximately 132 feet.

Byron's share of net production and sales from the SM58 G platform, comprising SM58 G1 and G2 wells and the SM69 E2 well, and for the year ended 30 June 2022 totalled 2,024,505 mmbtu of gas and 178,183 barrels of oil (June 2021 year 4,202,475 mmbtu of gas and 71,558 barrels of oil).

Oil production for the year ended 30 June 2022 was above the volumes achieved for the 2021 year mainly due to commencement of the E2 well production in October 2021. Gas production was down due to natural decline at the G1 well, platform shut-ins necessitated by named windstorms and downtime arising from shut-ins as a result of a leak in the third-party oil sales pipeline and the drilling of G3 and G5 wells.

As of 30 June 2022, the SM58 G facility has produced approximately 6.8 Bcfg and 0.3 million barrels of oil and condensate (gross) on a cumulative basis from three wells (G1, commenced production in September 2020 from the Upper O sand, G2, commenced production in October 2020 from the O Sand, and E2, commenced production on 21 October 2021 from the K4 sand).

The SM58 G1 well produces from the Upper O Sand and producing 56.5-degree gravity condensate and no formation water. Gas and oil 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.

Following the successful drilling and completion of the Company's SM69 E2 well, production began on 21 October 2021. The well has been in continuous production since then despite the normal challenges associated with commissioning a new production separator and associated production equipment on the host SM58 G platform. 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.

During the year ended June 2022 Byron successfully drilled the SM69 E2 well, the SM58 G3 (G3) and the SM58 G5 (G5) wells. To increase operational efficiency and reduce cost, the G3 and G5 wells were batch drilled by driving conductor pipe for each well, then drilling and cementing surface casing in each well before drilling the target sections in each well.

The well results are summarised below.

	E2*	G3	G5
Total measured depth	8,157 feet Measured Depth (MD) 7,648 feet True Vertical Depth (TVD)	8,642 feet MD/6,970 feet TVD	10,228 feet MD/8,244 feet TVD
Net pay logged	68 feet True Vertical Thickness (TVT) of net oil pay in three productive oil zones, the K Sand (B55), K4 Sand (B65) and the L2 Sand	J Sand logged 27 feet True Vertical Thickness (TVT) net pay; K4/B65 Sand, logged 31 feet of TVT net pay	The primary target N2 Sand logged 36 feet TVT; 81 feet TVT hydrocarbon pay in three secondary sands – 11 feet TVT pay in I2 sand, 23 feet TVT pay In K4/ B65 sand and 47 feet TVT pay in L2 sand
Completion	High-rate gravel pack completion with sliding sleeves in the primary K4 Sand with the L2 zone perforated and isolated as a future low-cost downhole zone change	Primary J Sand completion is gravel packed and the future K4 Sand completion is gravel packed behind a sliding sleeve. No rig required to move to K4 Sand	Primary L2 Sand completion is gravel packed, with future N2 Sand completion as a through tubing gravel pack. No rig is required to perform the through tubing gravel pack on the N2

* The E2 production flows through the previously laid E-to-G flowline and is processed through the Byron operated SM58 Facilities; unlike the SM69 E1 well production, E2 production is not subject to any third-party processing fees.

Both the G3 and G5 wells were completed and hooked up for production subsequent to 30 June 2022, during the September quarter 2022.

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 S ½ of the SE ¼ of the SE ¼ of SM58, as well as a 53% working interest in the SM69 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 SM58 E1 well and E platform, which is located in the NE corner of the SM69 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 2022, Byron's share of net production was 19,448 barrels of oil and 3,508 mmbtu, compared to 16,791 barrels of oil and 2,588 mmbtu in the June 2021 year.

Exploration and Evaluation Assets

South Marsh Island 60, 66 and 70

Byron holds a 100% WI and 87.5% NRI in SM60, SM66 and SM70. 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 SM60, 66 and 70 blocks were part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

Byron has received approval from BOEM on Development Operations Coordination Documents ("DOCD") filed on SM60 and 70. DOCD's are the initial environmental permits required prior to drilling new wells, setting new platforms and laying new pipelines.

Main Pass 306

Byron currently holds 100% WI and an 87.50% NRI on Main Pass blocks 293, 305 and 306 comprising the Main Pass 306 Field ("MP306", acquired at the Gulf of Mexico, Outer Continental Shelf ("OCS") Lease Sale 251 held in New Orleans, Louisiana, on 15 August 2018.

Byron recently licensed 3D RTM seismic data that was reprocessed by the contractor (TGS) in 2022 and has begun interpretation.

Portfolio Optimisation

During the year ended 30 June 2022, Byron relinquished the following properties:

(i) Eugene Island blocks 62, 63, 76 and 77 ("EI77"); and

(ii) South Marsh Island 57 ("SM57") and 59.

Byron relinquished the EI77 leases late in June 2022. In preparation of its annual accounts, the previously capitalised exploration and evaluation expenditure of approximately US$2.5 million was written down to nil and the EI77 undeveloped reserves and prospective resources were removed from the Company's booked reserves and resources.

Byron also took the opportunity to optimise its portfolio of exploration opportunities and relinquish SM57 in October 2021 and replace it with South Marsh Island 61 lease ("SM61"), assuming it is awarded to Byron. The SM57 lease did not have any reserves attributed to it.

Byron was the apparent high bidder on the SM61, the only bid placed by the Company at the Gulf of Mexico, OCS Lease Sale 257 held in New Orleans, Louisiana, on Wednesday, 17 November 2021.

The Company was sole bidder on the block with a bid of approximately US$130k on SM61. SM61 lies within the area of Byron's RTM reprocessing project, which was used to evaluate the prospect potential on the block. Subsequently to 30 June 2022, Byron was awarded the SM61 block by the Bureau of Ocean Energy Management ("BOEM").

Properties

As at 30 June 2022, 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 (Km^2)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 60	Byron	100.00/87.50	June 2024	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) (E2 well)	Byron	100.00/77.33-80.33	Production	1.30
Block 66	Byron	100.00/87.50	December 2025	20.23
Block 70	Byron	100.00/87.50	June 2023	22.13
Main Pass				
Block 293	Byron	100.00/87.50	October 2023	18.46
Block 305	Byron	100.00/87.50	October 2023	20.23
Block 306	Byron	100.00/87.50	October 2023	20.23

* Working Interest ("WI") and Net Revenue Interest ("NRI").
** 100.00% WI to a depth of 13,639 ft TVD and 50% WI below 13,639 ft TVD.

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.

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 Organisation 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 program. 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 unauthorised 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 programs)

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 20 January 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on 19 February 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 27 January 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 unfavourable 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 utilised 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 programs.

Executive Order 3395 went into effect on 20 January 2021 and has had no material effect on the process for permits on existing leases. Executive Order 3395 suspends new leasing activities for oil and gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices but does not apply to existing leases.

The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district court in June 2021, effectively halting implementation of the leasing suspension. Subsequent federal litigation, however, has impeded the most recent federal oil and gas lease sale in the Gulf of Mexico requiring the Department of Interior ("DOI") to conduct a new environmental analysis that takes into consideration such climate effects before holding another sale. In November 2021, the DOI released its report on federal oil and gas leasing and permitting practices. The report included recommendations in respect to offshore sector, including adjusting royalty rates to ensure that the full value of the tracts being leased are captured, strengthening financial assurance coverage amounts that are required by operators, 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. Several of the report recommendations require action by the Congress and cannot be implemented unilaterally by the Biden Administration.

In June 2022, the DOI issued the Proposed Program for the National Outer Continental Shelf Oil and Gas Leasing Program (National OCS Program) for years 2023-2028. Following publication in the Federal Register, the Interior Department will seek public comment on the Proposed Program and the accompanying Draft Programmatic Environmental Impact Statement (PEIS).

The Proposed Program was the next step in a process begun by the Trump administration, which had initially considered opening areas off the Atlantic and Pacific coasts but faced enormous opposition from coastal states.

The Proposed Program includes no more than 10 potential sales in the Gulf of Mexico (GOM) and one potential lease sale in the northern portion of the Cook Inlet Planning Area offshore Alaska, which is the same as in the Five-Year Program finalised in 2016. These potential lease sales, including in the GOM, could be further refined and targeted, based on public input and analysis, prior to program approval. The Final Program also may include fewer potential lease sales, including no lease sales.

Following the opportunity for public comment, BOEM will prepare a Proposed Final Program and Final PEIS, which will include analysis of the size, timing, location and number of potential lease sales in the Proposed Program. Those may be further narrowed or areas could be excluded. There is then a minimum 60-day period before the Secretary can approve the program and finalise the Record of Decision.

The Company continues to conduct operations on its existing leases in the OCS. However, uncertainty on future Biden Administration actions in relation to offshore oil and gas activities on the OCS together with the issuance of any future executive orders or adoption and implementation of laws, rules or initiatives that further restrict, delay or result in cancellation of existing oil and gas activities on the OCS could have a material adverse effect on business and operations.

Seismic risk

3D seismic data and visualisation 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 debt level and the covenants in current or future agreements governing the Company's debt including the Secured Promissory Note ("Promissory Note") issued to Crescent Midstream Operating, LLC (formerly Crimson Midstream Operating, LLC) 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 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 recognised 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.

Organisations 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 2022 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 7 July 2022 and 10 August 2022, Byron announced to the ASX that SM58 G3 and G5 wells commenced production of oil and gas from the SM58 G Platform;
- on 10 August 2022, Byron announced that (a) Byron's net daily production had reached 2,332 bopd and 7,154 mcf; (b) the SM71 F2 well commenced production from the J1 Sand recompletion; and (c) SM71 F4 well was also recompleted to the J1 Sand and was being brought online; and
- on 14 September 2022, Byron released its 2022 reserves and resources report.

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 (2021: 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 three 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	3	3
Paul A Young	4	2	3	3
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 2022. 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 2018 US$	30 June 2019 US$	30 June 2020 US$	30 June 2021 US$	**30 June 2022 US$**
Revenue (net of royalties)	9,544,507	31,324,061	21,402,255	35,837,228	**53,143,411**
Net profit before tax	1,298,968	5,718,988	68,348	5,854,375	**22,215,308**
Net profit after tax	1,298,968	5,718,988	68,348	5,854,375	**22,215,308**
Share price at start of year	A$0.095	A$0.335	A$0.29	A$0.14	**A$0.10**
Share price at end of year	A$0.355	A$0.29	A$0.14	A$0.10	**A$0.17**
Basic earnings per share	US$0.0022	US$0.0083	US$0.000088	US$0.005633	**US$0.02135**
Diluted earnings per share	US$0.0022	US$0.0080	US$0.000086	US$0.005587	**US$0.02096**

(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 sought to be approved by shareholders and the fee structure is reviewed annually.

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.

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 2022, the annual service fee was increased from A$605,000 to A$695,750.

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 its 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 2022, Mr Kallenberger's remuneration was increased from US$385,000 to US$442,750.

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 2022, Mr Sack's remuneration was increased from US$385,000 to US$442,750.

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$379,500 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 2022, Mr Filipovic's base remuneration was increased from A$330,000 to A$379,500.

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.

In January 2020, Byron issued 9,500,000 new shares to key management personnel, other senior staff and consultants following exercise of 9,500,000 unlisted options at A$0.25 each. The issue of these options was approved by shareholders on 24 November 2016. The Company provided unsecured three-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 held on 29 November 2019, and granted to key management personnel during the financial year. Loans outstanding as of 30 June 2022 are:

Key management personnel (borrower)	Principal sum (A$)	Interest rate %	Term
Maynard Smith	625,000	Nil	3 years
Prent Kallenberger	625,000	Nil	3 years
William Sack	625,000	Nil	3 years
Nick Filipovic	250,000	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.

Further, in January 2022 Byron issued 41,100,000 new shares to key management personnel, other senior staff and consultants following exercise of 41,100,000 unlisted options, 28,350,000 exercisable at A$0.12 each, 2,000,000 exercisable at A$0.16 each and 10,750,000 exercisable at A$0.40 each. The 41,100,000 new shares are classified as treasury shares for accounting purposes.

The issue of 39,100,000 unlisted options was approved by shareholders at general meetings of the Company held on 18 September 2017 and 20 November 2018 to Maynard Smith, Prent Kallenberger, William Sack, their associates and certain senior managers and consultants of the Company or their respective nominees. A further 2,000,000 Options were issued to employees of the Company without shareholder approval.

The Company provided unsecured three-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 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 2022 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 options of Byron Energy Limited are as follows:

Ordinary Shares

Director/key management personnel	Balance on 30 June 2021 Number	Granted as compensation Number	Received on exercise of options* Number	Net other changes Number	Balance on 30 June 2022 Number
D Battersby	57,250,568	–	–	50,000	57,300,568
M Smith	40,625,664	–	8,400,000	22,327	49,047,991
P Kallenberger	4,408,762	–	8,400,000	–	12,808,762
C Sands	24,710,783	–	–	–	24,710,783
P Young	27,352,773	–	–	93,846	27,446,619
W Sack	6,900,001	–	8,400,000	–	15,300,001
N Filipovic	2,721,359	–	5,180,000	(600,000)	7,301,359

* These new shares are classified as treasury shares for accounting purposes.

During the financial year, no shares or share options were granted to directors or other key management personnel of the Company. Executive directors and key management personnel converted 30,380,000 share options to ordinary shares via interest free loans approved by shareholders at the Company's 2021 AGM.

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 a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in September 2021, however, the directors agreed to extend the loan repayment date to March 2023 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 2022 was A$140,000, plus A$11,507 has been accrued as at 30 June 2022;
- 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 2022 was A$17,500, plus A$1,438 has been accrued as at 30 June 2022;
- 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 2022 was A$17,500, plus A$1,438 has been accrued as at 30 June 2022;

- 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 2022 was US$100,000, plus US$8,219 has been accrued as at 30 June 2022; 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 2022 was US$90,000 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2022.

	Short-term employee benefits				Post-employment benefits	Share-based payments	
2022	**Salaries and fees US$**	**Short-term cash incentive US$**	**Other benefits US$**	**Service agreements US$**	**Super-annuation US$**	**Exercise of share options* US$**	**Total US$**
Directors							
D Battersby	**–**	**–**	**–**	**58,064**	**–**	**–**	**58,064**
M Smith	**–**	**–**	**–**	**472,042**	**–**	**314,226**	**786,268**
P Kallenberger	**413,875**	**–**	**32,341**	**–**	**–**	**314,226**	**760,442**
C Sands	**29,032**	**–**	**–**	**–**	**–**	**–**	**29,032**
P Young	**29,032**	**–**	**–**	**–**	**2,903**	**–**	**31,935**
W 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.

	Short-term employee benefits				Post-employment benefits	Share-based payments	
2021	**Salaries and fees US$**	**Short-term cash incentive US$**	**Other benefits US$**	**Service agreements US$**	**Super-annuation US$**	**100% vested share options US$**	**Total US$**
Directors							
D Battersby	–	–	–	59,744	–	–	59,744
M Smith	–	–	–	451,814	–	–	451,814
P Kallenberger	385,000	–	31,236	–	–	–	416,236
C Sands	29,872	–	–	–	–	–	29,872
P Young	29,872	–	–	–	2,838	–	32,710
W Sack	385,000	–	30,391	–	–	–	415,391
N Filipovic	246,444	–	–	–	23,412	–	269,856
	1,076,188	–	61,627	511,558	26,250	–	1,675,623

Bonuses

Nil bonuses were granted to executive directors and the key management personnel during the financial year ended 30 June 2022 (2021: 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 Battersby
Chairman

30 September 2022

Auditor’s Independence Declaration

Deloitte.

Deloitte Touche Tohmatsu
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30 September 2022

The Board of Directors
Byron Energy Limited
Level 4, 480 Collins Street
MELBOURNE VIC 3000

Dear Board Members

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 statements of Byron Energy Limited for the financial year ended 30 June 2022, I declare that to the best of my knowledge and belief, there have been no contraventions of:

(i) the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and

(ii) any applicable code of professional conduct in relation to the audit.

Yours sincerely

Deloitte Touche Tohmatsu
DELOITTE TOUCHE TOHMATSU

Craig Bryan
Partner
Chartered Accountants

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the Financial Year Ended 30 June 2022

	Note	Consolidated 2022 US$	2021 US$
Continuing operations			
Revenues from sale of oil and gas		**64,727,503**	43,260,597
Royalty expense		**(11,584,092)**	(7,423,369)
Cost of sales	2	**(19,105,413)**	(20,793,128)
Gross profit		**34,037,998**	15,044,100
Recoupment of operator overheads		**293,271**	297,799
Realised loss on forward commodity price contracts	16	**(481,461)**	(369,734)
Corporate and administration costs		**(2,920,851)**	(2,547,239)
Impairment expense/dry hole expense	8(a)	**(3,082,807)**	(595,951)
Share-based payments		**(1,599,464)**	–
Depreciation/amortisation of property, plant and equipment		**(484,697)**	(560,354)
Other expenses		**(1,412,030)**	(1,986,508)
Financial income	3	**132,815**	53,337
Financial expense	3	**(2,267,466)**	(3,481,075)
Profit before tax		**22,215,308**	5,854,375
Income tax expense	4	**–**	–
Profit for the year from continuing operations		**22,215,308**	5,854,375
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Cumulative loss on oil price cash flow hedges reclassified to profit and loss	18	**428,596**	123,570
Oil price financially settled swaps written down to fair value	18	**–**	(428,596)
Exchange differences on translating the parent entity group		**11,600**	99,922
Total comprehensive income for the year		**22,655,504**	5,649,271
Earnings per share			
Basic (cents per share)	5	**2.135**	0.5633
Diluted (cents per share)	5	**2.096**	0.5587

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

At 30 June 2022

	Note	Consolidated 2022 US$	Consolidated 2021 US$
Assets			
Current assets			
Cash and cash equivalents	21(b)	**14,087,032**	4,143,411
Trade and other receivables	6	**7,492,552**	4,197,380
Other	7	**2,257,545**	2,291,909
Total current assets		**23,837,129**	10,632,700
Non-current assets			
Exploration and evaluation assets	8(a)	**2,545,486**	5,150,621
Oil and gas properties	8(b)	**121,751,736**	95,433,081
Other	7	**1,783,007**	1,925,000
Right-of-use assets	9	**1,002,348**	1,454,296
Trade and other receivables	6	**102,335**	180,398
Property, plant and equipment	11	**23,427**	31,472
Other intangible assets	12	**–**	25,275
Total non-current assets		**127,208,339**	104,200,143
Total assets		**151,045,468**	114,832,843
Liabilities			
Current liabilities			
Trade and other payables	13	**16,797,661**	2,022,359
Provisions	14	**182,950**	173,682
Derivative financial instruments	16	**–**	476,913
Lease liabilities	10	**568,183**	509,143
Borrowings	15	**20,978,748**	16,302,006
Total current liabilities		**38,527,542**	19,484,103
Non-current liabilities			
Trade and other payables	13	**325,000**	–
Provisions	14	**5,957,795**	7,183,789
Lease liabilities	10	**723,539**	1,291,722
Borrowings	15	**–**	5,640,364
Total non-current liabilities		**7,006,334**	14,115,875
Total liabilities		**45,533,876**	33,599,978
Net assets		**105,511,592**	81,232,865
Equity			
Issued capital	17	**139,117,070**	139,093,311
Foreign currency translation reserve	18	**(35,118)**	(46,718)
Cash flow hedge reserve	18	**–**	(428,596)
Share option reserve	18	**7,904,533**	6,305,069
Accumulated losses		**(41,474,893)**	**(63,690,201)**
Total equity		**105,511,592**	**81,232,865**

The accompanying notes form part of these financial statements.

Consolidated Statement of Changes in Equity

For the Financial Year Ended 30 June 2022

Consolidated entity	Ordinary share capital US$	Share option reserve US$	Other reserves US$	Accumulated losses US$	Total US$
Balance at 1 July 2020	137,560,738	6,305,069	(270,210)	(69,544,576)	74,051,021
Profit for the year	–	–	–	5,854,375	5,854,375
Change in value of financially settled swaps written down to fair value	–	–	(428,596)	–	(428,596)
Change in value of cash flow hedges	–	–	123,570	–	123,570
Exchange differences arising on translation of the parent entity group	–	–	99,922	–	99,922
Total comprehensive profit for the year	–	–	(205,104)	5,854,375	5,649,271
The placement of 16,745,771 shares at a subscription price of A$0.13 cents per share	1,532,573	–	–	–	1,532,573
Balance at 30 June 2021	139,093,311	6,305,069	(475,314)	(63,690,201)	81,232,865
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**

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

For the Financial Year Ended 30 June 2022

	Note	Consolidated 2022 US$	Consolidated 2021 US$
Cash flows from operating activities			
Receipts from customers		**60,685,271**	42,674,868
Payments to suppliers and employees		**(21,687,710)**	(18,187,987)
Interest paid		**(2,435,083)**	(3,136,320)
Interest received		**49,932**	1,499
Net cash flows from operating activities	21(a)	**36,612,410**	21,352,060
Cash flows from investing activities			
Payments for development of oil and gas properties		**(7,501,567)**	(34,007,000)
Payments for exploration and evaluation assets		**(18,042,292)**	(1,034,993)
Net cash flows used in investing activities		**(25,543,859)**	(35,041,993)
Cash flows from financing activities			
Proceeds from issues of ordinary shares		**–**	1,532,573
Proceeds from exercise of options		**23,759**	–
Payment of equity raising costs		**–**	(35,919)
Repayment of lease liabilities		**(561,621)**	(499,828)
Repayment of borrowings (including prepaid revenue repayments)		**(15,575,242)**	(3,417,003)
Proceeds from borrowings (including prepaid revenue receipts)		**15,000,000**	3,500,000
Net cash flows (used in)/from financing activities		**(1,113,104)**	1,079,823
Net increase/(decrease) in cash and cash equivalents held		**9,955,447**	(12,610,110)
Cash and cash equivalents at the beginning of the year		**4,143,411**	16,644,701
Effect of exchange rate changes on the balance of cash held in foreign currencies		**(11,826)**	108,820
Cash and cash equivalents at the end of the year	21(b)	**14,087,032**	4,143,411

The accompanying notes form part of these financial statements.

Notes to the Financial Statements
For the Financial Year Ended 30 June 2022

Note **Contents**

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 30 September 2022.

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 judgements and key sources of estimation uncertainty

The preparation of the consolidated financial statements requires management to make judgements, 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 judgements 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 14.

Working capital management

The financial report has been prepared on the going concern basis which assumes the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business for a period of at least 12 months from the date of signing the financial report.

The primary activities of the consolidated entity comprise the exploration for and development and production of oil and gas in the shallow water offshore Louisiana in the Gulf of Mexico.

For the year ended 30 June 2022 the consolidated entity reported a profit before tax of US$22,215,308 after recognising impairment and dry hole expenses of US$3,082,807 and generated net cash inflows from operating activities of US$36,612,410. As at 30 June 2022 the consolidated entity reported a working capital deficiency of US$14,690,413.

This deficiency principally arises from:

(i) existing borrowings from a third party totalling US$4,830,114 that is due for repayment in the next five months;

(ii) an oil revenue prepayment of US$11,000,000 with the buyer of the Company's oil production;

(iii) existing borrowings from certain directors and a long-standing shareholder totalling US$3,446,690 that are due for repayment in the next nine months; and

(iv) excess cash flow generated by the Group over the year ended 30 June 2022 has been invested in various exploration and development activities which are presented as non-current assets at year end.

1. Summary of significant accounting policies (continued)

The consolidated entity has prepared a Board approved forecast for the 12 months ending 30 September 2023 which highlights that the consolidated entity has sufficient cash reserves to continue normal business operations as planned. The cash flow forecast is based on certain key assumptions including the successful completion and production of additional wells over the forecast period, the upfront payment for future oil production from a key customer, as well as the sales prices to be realised on unhedged oil and gas sales. To the extent these assumptions do not occur as planned or the expected timings of the forecast events are delayed, the consolidated entity may be required to source additional funding to continue operations and settle its obligations with existing suppliers and financiers.

For the year ended 30 June 2022 and in prior periods the consolidated entity has raised sufficient funding to continue operating as planned through various means including:

(i) Oil Revenue prepayments with the buyer of the Company's oil production;

(ii) interest bearing debt finance;

(iii) extended terms of trade with certain key service industry suppliers; and

(iv) equity capital.

Having considered all relevant facts the directors are satisfied that is appropriate to prepare the financial report on the going concern basis. However, in the event that the consolidated entity is unsuccessful in the matters set out above, a material uncertainty would exist that may cast significant doubt as to whether the consolidated entity will be able to continue as a going concern and therefore whether it will realise its assets and discharge its liabilities in the normal course of business and at the amounts stated in the financial report.

The financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or to the amounts and classification of liabilities that might be necessary should the consolidated entity not continue as a going concern.

Adoption of new and revised Accounting Standards

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations (for which Australian equivalent Standards and Interpretations have not yet been issued) 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 2020-3 Amendments to Australian Accounting Standards – Annual Improvements 2018-2020 and Other Amendment	1 January 2022	30 June 2023
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 2023	30 June 2024
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

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.

(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 farm-outs, 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 farm-ins, 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 assets 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.

1. Summary of significant accounting policies (continued)

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.

(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.

(h) Revenue recognition

Oil and gas revenue

Revenue associated with the sale of crude oil, natural gas, condensate and natural gas liquids ("NGLs") owned by the Company is recognised when title is transferred from the Company to its customers under short-term contracts (less than 12 months). Revenue is measured at the fair value of the consideration received or receivable. Revenue from the sale of crude oil, natural gas, condensate and NGLs is recognised when all of the following conditions have been satisfied:

- Byron has transferred control of the goods to the buyer and revenue is recognised at that time;
- Byron retains no continuing managerial involvement to the degree usually associated with ownership or effective control over the goods sold;
- the amount of revenue can be measured reliably;
- it is probable that the economic benefits associated with the transaction will flow to Byron; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

The Company recognises oil, natural gas and NGL revenues based on its share of the quantities of production, solely owned or under joint ownership, sold to purchasers under short-term contracts at market prices.

Interest revenue

Interest revenue 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.

1. Summary of significant accounting policies (continued)

(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 to 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.

(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 (including software)

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
Intangible assets – software	2.5 to 3 years

1. Summary of significant accounting policies (continued)

(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 cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

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 cash flows 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 to 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.

(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. 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).

Cash flow hedging reserve

The cash flow 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 cash flow hedges is made in note 1(r) Derivative financial instruments – cash flow hedges.

(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

The Group enters into a variety of derivative financial instruments to manage its exposure to crude oil price risks, including cash flow hedges. Further details of derivative financial instruments are disclosed in note 16.

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.

1. Summary of significant accounting policies (continued)

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 the 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 contracts 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

Profit for the year has been arrived at after charging the following items of expense

	Consolidated	
	2022 US$	**2021 US$**
Cost of sales		
Lease operating costs	**6,690,581**	5,959,274
Gas transportation costs	**836,437**	1,595,962
Amortisation of oil and gas properties	**11,578,395**	13,237,892
	19,105,413	20,793,128
Professional and consulting costs	**927,343**	1,489,788
Insurance	**193,236**	142,674
Office lease rental expense including outgoings (short-term leases)	**132,877**	136,258
Employee benefits expense		
Salaries and wages	**2,155,288**	1,791,962
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)	**1,070,720**	–
Defined contribution superannuation expense	**36,315**	33,021
	3,262,323	1,824,983

3. Financial income and expenses

	Consolidated	
	2022 US$	2021 US$
Financial income		
Interest income	725	53,337
Foreign exchange gain on A$ denominated loans	132,090	–
	132,815	53,337
Financial expense		
Interest expense non related parties	1,664,511	2,801,944
Foreign exchange loss on A$ denominated loans	–	137,550
Lease finance costs	130,542	148,547
Unwinding of discount on rehabilitation of oil and gas properties	116,979	42,455
Interest expense paid or accrued on loans from related parties	355,434	350,579
	2,267,466	3,481,075

4. Income tax

	2022 US$	2021 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	22,215,308	5,854,375
Income tax expense calculated at 30.0% (2021: 26.0%)	6,664,592	1,522,138
Effect of expenses that are not deductible in determining taxable profit	479,839	3,730
Effect of income that is not assessable in determining taxable profit	–	(11,650)
Effect of different tax rates of subsidiaries operating in other jurisdictions	(250,059)	6,840
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	(6,894,372)	(1,521,058)
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	4,886,128	4,144,962
USA tax losses	35,973,460	36,011,315
Temporary differences	(28,960,359)	(22,884,322)
Total deferred tax assets not recognised	11,899,229	17,271,955

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.

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	
	2022 US$	**2021 US$**
Net profit for the year	**22,215,308**	5,854,375
Basic profit per share	**0.02135**	0.005633
Diluted profit per share	**0.02096**	0.005587
Weighted average number of ordinary shares	**1,040,295,102**	1,039,331,647
Treasury shares	**19,592,877**	–
Shares deemed to be issued for no consideration in respect of share options	**–**	8,543,288
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	**1,059,887,979**	1,047,874,935
Anti-dilutive options on issue not used in the dilutive earnings per share calculation	**–**	32,200,000

6. Trade and other receivables

Current		
Oil and gas sales receivables	**7,337,734**	3,970,390
Joint operating arrangements receivables	**129,491**	145,252
Interest receivable	**424**	51,858
GST receivable	**24,903**	29,880
	7,492,552	4,197,380
Non-current		
Joint operating arrangements receivables	**102,335**	180,398

Current trade and other receivables are non-interest bearing and are settled within 45 days. Consequently, the amounts referred to in this note are less than 45 days to collection, except for a joint venture receivable that was collected in full, subsequent to 30 June 2022.

7. Other assets

Current		
Prepayments	**2,251,538**	2,285,353
Security deposits	**6,007**	6,556
	2,257,545	2,291,909
Non-current		
Security deposits	**1,783,007**	1,925,000

8(a). Exploration and evaluation assets

	Consolidated	
	2022 US$	**2021 US$**
Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**2,545,486**	5,150,621
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**5,150,621**	4,695,861
Additions at cost	**18,476,352**	1,050,711
Transfers of exploration and evaluation assets to oil and gas properties 8(b)	**(17,998,680)**	–
Impairment expense	**(3,082,807)**	(595,951)
Carrying amount at the end of the financial year	**2,545,486**	5,150,621

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 2022, impairment charges were US$3,082,807 due to (i) relinquishment of the Eugene Island 62, 63, 76 and 77 leases, and (ii) relinquishment of the SM57 lease.

8(b). Oil and gas properties

Costs carried forward in respect of areas in the oil and gas properties:	**121,751,736**	95,433,081
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**95,433,081**	37,224,157
Additions at cost	**21,253,667**	31,432,130
Additions/(subtractions) for site restoration	**(1,355,297)**	2,047,252
Transfers from exploration and evaluation assets 8(a)	**17,998,680**	37,967,434
Amortisation of oil and gas properties included in cost of sales	**(11,578,395)**	(13,237,892)
Carrying amount at the end of the financial year	**121,751,736**	95,433,081

Recoverable amount

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 of 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), (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.

For the 2022 financial year, the following assumptions were used in the assessment of recoverable amounts: (i) oil prices used in this report represent 18 July 2022, NYMEX West Texas Intermediate (WTI) Strip prices starting on 1 July 2022, of $104.76 per barrel. Beginning 1 January 2023, the Reuters Poll consensus pricing was used with a starting price of $92.19 per barrel and with a final price of $80.23 per barrel on 1 January 2026, then held constant thereafter; (ii) gas prices (nominal) used in this report represent a Henry Hub base 18 July NYMEX Strip prices starting on 1 July 2022, of $7.427 per MMBtu. Beginning 1 January 2023, the Reuters Poll consensus pricing was used with a starting price of $4.700 per MMBtu, declining to $4.000 per MMBtu on 1 January 2024, then held constant thereafter. These prices were then adjusted to account for transportation cost, basis difference, Light Louisiana Sweet (LLS) vs WTI oil gravity; and (iii) post-tax nominal discount rate of 11.5%.

At year end, the Company's oil and gas properties were assessed for impairment indicators in accordance with AASB 136. Following this assessment, no impairment was required or recognised on the oil and gas properties during the 30 June 2022 financial year.

9. Right-of-use assets

	Consolidated 2022 US$	Consolidated 2021 US$
Office lease		
Opening balance	**485,819**	673,878
Amortisation	**(188,059)**	(188,059)
Carrying amount at the end of the financial period	**297,760**	485,819
Compressor lease		
Opening balance	**968,477**	314,822
Additions	**–**	871,666
Amortisation	**(263,889)**	(218,011)
Carrying amount at the end of the financial period	**704,588**	968,477
Total right-of-use assets	**1,002,348**	1,454,296
Amounts recognised in profit and loss		
Amortisation expense on right-of-use assets	**451,948**	406,070
Interest expense on lease liabilities	**130,542**	148,547
Expense relating to short-term leases including outgoings	**132,877**	136,258

10. Lease liabilities

	2022 US$	2021 US$
Not later than one year	**669,793**	664,821
Later than one year and not later than five years	**783,078**	1,452,871
Minimum lease payments	**1,452,871**	2,117,692
Less: Future finance charges	**(161,149)**	(316,827)
Provided for in the financial statements	**1,291,722**	1,800,865
Representing lease liabilities:		
Current	**568,183**	509,143
Non-current	**723,539**	1,291,722
	1,291,722	1,800,865

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 2022 US$	2021 US$
Buildings at cost	**10,064**	10,983
Accumulated depreciation	**(4,040)**	(4,135)
	6,024	6,848
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**6,848**	6,503
Depreciation for year	**(265)**	(273)
Foreign currency translation movements	**(559)**	618
Carrying amount at the end of the financial year	**6,024**	6,848
Plant and equipment at cost	**132,288**	135,359
Accumulated depreciation	**(114,885)**	(110,735)
	17,403	24,624
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**24,624**	33,973
Additions at cost	**–**	–
Depreciation for year	**(7,209)**	(9,379)
Foreign currency translation movements	**(12)**	30
Carrying amount at the end of the financial year	**17,403**	24,624
Total property, plant and equipment	**23,427**	31,472

12. Other intangible assets

	2022 US$	2021 US$
Capitalised software costs at cost	**465,738**	479,408
Accumulated amortisation	**(465,738)**	(454,133)
	–	25,275
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**25,275**	165,329
Amortisation for year	**(25,275)**	(144,514)
Foreign currency translation movements	**–**	4,460
Carrying amount at the end of the financial year	**–**	25,275

13. Trade and other payables

	Consolidated 2022 US$	Consolidated 2021 US$
Current		
Trade payables	**15,383,015**	1,281,781
Oil and gas royalties payable	**1,369,350**	694,461
Accrued interest on loans	**27,507**	28,593
Other payables	**17,789**	17,524
	16,797,661	2,022,359
Non-current		
Trade payables	**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.

14. Provisions

	2022 US$	2021 US$
Current		
Accumulated employee entitlements	**182,950**	173,682
	182,950	173,682
Non-current		
Accumulated employee entitlements	**101,494**	89,170
Site restoration SM71 wells, pipelines and platform, SM58 E1 and SM69 E2 wells, SM69 pipelines and platform, SM58 wells and SM58 pipelines and platform	**5,856,301**	7,094,619
	5,957,795	7,183,789
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**7,094,619**	5,004,912
Additions/(subtractions) to site restoration	**(1,355,297)**	2,047,252
Unwinding of discount on site restoration	**116,979**	42,455
Carrying amount at the end of the financial year	**5,856,301**	7,094,619

Provisions are recognised for the Group's restoration obligations for the SM71 wells and platform, SM58 E1 and SM69 E2 wells, SM58 G1, G2ST, G3 and G5 wells, SM58 and SM69 pipelines and 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 a number of 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 2022 were within the range of 3.09% to 3.12% (2021 within the range of 1.51% to 2.0%), 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).

15. Borrowings

	Consolidated 2022 US$	2021 US$
Current unsecured		
Loans from directors and shareholder*	**3,446,690**	3,578,780
Prepaid oil revenues**	**11,000,000**	1,750,000
Insurance premium financing (interest bearing)***	**1,701,944**	1,530,593
Current secured		
Promissory note – debt liability	**4,830,114**	9,442,633
Total current borrowings	**20,978,748**	16,302,006
Non-current secured		
Promissory note – debt liability****	**–**	5,640,364
Total non-current borrowings	**–**	5,640,364

* The loan facility was fully drawn during the March 2019 quarter, is unsecured and repayable by 31 March 2023 (unless otherwise agreed) and bears interest from time of drawdown, at a rate of 10% per annum, payable every quarter. The increase in the loans for the period is solely due to the strength in the Australia dollar relative to the USA dollar.

** Prepaid oil revenues incur a USD 97 cents a barrel charge on Byron's oil production from initial prepayment date to full repayment. The current prepayment balance will be repaid over an eight-month period in equal instalments, beginning in August 2022.

*** The insurance premium financing bears an average 3.91% fixed interest rate, refer note 30(c).

**** Crescent (formerly Crimson) Promissory note: key terms of the Promissory note include: (i) facility amount US$18.5 million; and (ii) senior secured debt over the Company's SM71 and SM58 assets and guaranteed by the Company and will be fully repaid by November 2022.

16. Oil price financially cash settled swaps

In March 2021, Byron hedged 200 barrels of oil per day for the period March to December 2021 in the form of financially settled swaps with an average strike price of US$62 per barrel on the West Texas Intimidate (WTI) base price.

	2022 US$	2021 US$
Oil price financially cash settled swaps – unrealised loss		
Carrying amount at the beginning of the financial year	**476,913**	–
Reverse write down of unrealised loss on oil price financially settled swaps to fair value on 30 June 2021 through other comprehensive income	**(428,596)**	–
June 2021 oil price cash settled hedges payment made in July 2021	**(48,317)**	–
Unrealised loss on oil price financially settled swaps to fair value on 30 June 2021 through other comprehensive income	**–**	476,913
Net amount	**–**	476,913
Oil price financially cash settled swaps – realised loss		
Realised loss on oil price cash flow hedges for the year ended 30 June 2022	**481,461**	369,734

17. Issued capital

	Consolidated 2022 US$	Consolidated 2021 US$
(a) Issued and paid up capital	**139,117,070**	139,093,311

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

	2022		2021	
	Number	US$	Number	US$
Fully paid ordinary shares				
Balance at beginning of the financial year	**1,040,295,102**	**139,093,311**	1,023,549,331	137,560,738
Options converted to fully paid shares	**41,100,000***	**–**	–	–
Issue of shares on exercise of options	**–**	**23,759**	–	–
The placement of 16,745,771 shares at a subscription price of A$0.13 cents per share	**–**	**–**	16,745,771	1,532,573
Closing balance at end of financial year	**1,081,395,102**	**139,117,070**	1,040,295,102	139,093,311
Less shares classified as treasury shares				
Balance at beginning of the financial year	**–**	**–**	–	–
Conversion of options to fully paid shares	**41,100,000***	**–**	–	–
Closing balance at end of financial year	**41,100,000***	**–**	–	–
Closing balance at end of financial year	**1,040,295,102**	**139,117,070**	1,040,295,102	139,093,311

* 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 (2021: 1,040,295,102). All of 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, 41,100,000 share options were converted to fully paid ordinary shares comprising:

Expiry date	Number	Securities	Exercise price
31 December 2021	**28,350,000**	**Unlisted options**	**A$0.12**
31 December 2021	**2,000,000**	**Unlisted options**	**A$0.16**
31 December 2021	**9,500,000**	**Unlisted options**	**A$0.40**
31 December 2021	**1,250,000**	**Unlisted options**	**A$0.40**
Total	**41,100,000**		

At the end of the financial year, there were 2,000,000 (2021: 41,100,000) 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**		

2,000,000 share options were issued at an exercise price of A$ 16 cents per share during the financial year. No share options expired unexercised during the financial year.

18. Reserves

	Consolidated	
	2022 US$	**2021 US$**
Foreign currency translation reserve		
Balance at beginning of financial year	**(46,718)**	(146,640)
Currency translation movements for the year	**11,600**	99,922
Balance at end of financial year	**(35,118)**	(46,718)
The reserve arises out of the translation of A$, being the functional currency of the parent entity group into the consolidated entity presentation currency of US$.		
Cash flow hedging reserve		
Balance at beginning of financial year	**(428,596)**	(123,570)
Reverse write down of oil price cash flow hedge assets to fair value through other comprehensive income	**428,596**	123,570
Write down of oil price financially cash settled swap hedge liabilities to fair value through other comprehensive income	**–**	(428,596)
Balance at end of financial year	**–**	(428,596)
The reserve arises out of the movement in mark-to-market value of oil price hedges as at 30 June 2021.		
Share option reserve		
Balance at beginning of financial year	**6,305,069**	6,305,069
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	**7,904,533**	6,305,069

* In January 2022, Byron issued 41,100,000 new shares, treated as treasury shares for accounting purposes, to key management personnel, other senior staff and consultants following exercise of 41,100,000 unlisted options. The Company provided unsecured three-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 2021 annual general meeting held on 29 November 2021, and granted to key management personnel during the financial year. 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.

19. Franking credits

There are no franking credits available for distribution (2021: 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 2022.

(a) Commitments for office lease rental payments

	Consolidated	
	2022 US$	**2021 US$**
Not longer than one year	**20,594**	23,847
	20,594	23,847

(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 program commitments.

(c) Well expenditure commitments

The Group has a financial commitment as at balance date for the completions of the SM58 G3 and G5 wells and the recompletions of SM71 F2 and F4 wells.

Commitments for well completion and recompletion expenditures		
Not longer than one year	**15,880,680**	2,025,000

20(ii). Oil sales delivery commitments

The Group has oil sales delivery commitments at the end of the financial year for fixed volumes of barrels of oil.

	Oil barrels	Average price US$ bbl	Value of committed sales US$
Not longer than one year	**91,600**	**58.2513**	**5,335,820**

21. Cash flow reconciliation

	Consolidated 2022 US$	Consolidated 2021 US$
(a) Reconciliation of profit from ordinary activities after tax to net cash flows from operations		
Profit for the year	**22,215,308**	5,854,375
Non cash flows in operating result:		
Amortisation oil and gas properties	**11,578,395**	13,237,892
Depreciation and amortisation of property, plant, equipment and intangibles	**32,749**	154,282
Depreciation of right of use assets	**451,948**	406,071
Impairment expense	**3,082,807**	595,951
Equity settled share-based payments	**1,599,464**	–
Oil price hedges written down to zero	**–**	386,878
Finance cost of leased assets	**130,542**	148,547
Net foreign exchange (gain)/loss on A$ loans	**(132,090)**	137,550
Unwinding of discount on rehabilitation of oil and gas properties	**116,979**	42,455
Write off joint venture bad debt	**–**	33,243
Foreign exchange differences arising on translation of the parent entity group	**(5,261)**	15,732
	39,070,841	21,012,976
Movements in working capital		
(Increase)/decrease in assets:		
Trade and other receivables	**(3,313,982)**	(2,391,678)
Other assets	**187,349**	252,090
Increase/(decrease) in liabilities:		
Trade and other payables	**624,619**	706,535
Prepaid oil revenue	**–**	1,750,000
Provisions	**43,583**	22,137
Net cash from operating activities	**36,612,410**	21,352,060
(b) Reconciliation of cash		
Cash and cash equivalents comprise:		
Cash and bank balances	**14,087,032**	4,143,411

(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.

Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2022

22. 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%

23. 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:

	2022	2021
Spot rate at 30 June	**0.6889**	0.7518
Average rate for year	**0.7258**	0.7468

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 or the amount is not capable of reliable measurement.

(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 the Secured Promissory Note between Byron Energy Inc and Crescent Midstream Operating, LLC effective as of 3 December 2019.

(c) 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.

(d) 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.

(e) 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 2022, Byron had collateral bond holdings of US$5,618,356 (2021: US$4,918,356), of which US$1,783,007 (2021: US$1,925,000) was cash collateralised.

(f) 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.

25. Share-based payments

Movements in share-based payments options

The aggregate share-based payments paid as remuneration for the financial year are set out below:

	Consolidated	
	2022 US$	**2021 US$**
Details of share-based payments:		
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	**1,599,464**	–

41,100,000 share options were exercised and converted to fully paid shares during the financial year (2021: nil). There are no Employee Share Option Plans in place.

	2022	**2022**	**2021**	**2021**
	Number	**Exercise price**	**Number**	**Exercise price**
Balance at beginning of year	**41,100,000**	**–**	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**	**–**	41,100,000	–
Exercisable at end of year	**2,000,000**	**A$0.16c**	–	–
Exercisable at end of year	**–**	**–**	28,350,000	A$0.12c
Exercisable at end of year	**–**	**–**	2,000,000	A$0.16c
Exercisable at end of year	**–**	**–**	10,750,000	A$0.40c

Weighted average remaining contractual life

The 2,000,000 share options have an expiry of 915 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 of equity share options issued

The total fair value of all share options granted and issued during the financial year was US$84,517. Options were priced using the Binominal Option Pricing model and calculated by an independent external consultant entity. The fair value option price was A$5.82 cents.

Inputs into the model	2,000,000 share options were issued to two staff members on 11 January 2022
Closing share price prior to valuation	A$0.12.5
Exercise price	A$0.160
Expected volatility	81.67%
Option life	2.97 years
Risk-free interest rate	0.987%

25. Share-based payments (continued)

Calculation of the fair value of a loan funded conversion of equity share options into fully paid shares

The total fair value of the loan funded conversion of share options into fully paid ordinary shares, treated as treasury shares for accounting purposes during the 2022 financial year was US$1,514,947. The fair value was calculated by an independent external consultant entity that determined the share option conversions should be valued as synthetic options using the Binomial Option Pricing model.

Tranche A Inputs into the model	28,350,000 share options converted to fully paid ordinary shares to directors, staff and consultants as at 31 December 2021
Share option exercise price	A$0.120
Share price 31 December 2021	A$0.115
Number of options	28,350,000
Volatility	81.686%
Time maturity of underlying option	3 years
Risk-free interest rate	0.92%

Tranche B Inputs into the model	2,000,000 share options converted to fully paid ordinary shares to a staff member as at 31 December 2021
Share option exercise price	A$0.160
Share price 31 December 2021	A$0.115
Number of options	2,000,000
Volatility	81.686%
Time maturity of underlying option	3 years
Risk-free interest rate	0.92%

Tranche C Inputs into the model	10,750,000 share options converted to fully paid ordinary shares to directors, staff and consultants as at 31 December 2021
Share option exercise price	A$0.400
Share price 31 December 2021	A$0.115
Number of options	10,750,000
Volatility	81.686%
Time maturity of underlying option	3 years
Risk-free interest rate	0.92%

26. Employee benefits and superannuation commitments

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

27. Auditor's remuneration

	Consolidated	
	2022 US$	**2021 US$**
Amounts received or due and receivable by Deloitte Touche Tohmatsu:		
Audit or review of the financial statements of the Group	**73,219**	70,834
	73,219	70,834

The auditors did not receive any other benefits (2021: nil).

28. 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$**	**Super-annuation US$**	**Interest free loans to exercise share options US$**	**Total US$**
Year 2022	**1,143,292**	**–**	**67,228**	**530,106**	**28,651**	**1,134,034**	**2,903,311**
Year 2021	1,076,188	–	61,627	511,558	26,250	–	1,675,623

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

29. Related party transactions

The following related party transactions were made during the financial year ended 30 June 2022:

(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 a total drawdown of US$2,000,000 and A$1,750,000. The loans were due for repayment in November 2019; however, the directors agreed to extend the loan repayment date to March 2023 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 2022 was A$140,000, plus A$11,507 has been accrued as at 30 June 2022;
- 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 2022 was A$17,500, plus A$1,438 has been accrued as at 30 June 2022;
- 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 2022 was A$17,500, plus A$1,438 has been accrued as at 30 June 2022;
- 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 2022 was US$100,000, plus US$8,219 has been accrued as at 30 June 2022; 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 2022 was US$90,000 (net of withholding taxes), plus US$7,397 (net of withholding taxes) has been accrued as at 30 June 2022.

29. Related party transactions (continued)

(b) As at 30 June 2022, 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 three-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.

Key management personnel (borrower)	Principal sum (A$)	Interest rate %	Term
Maynard Smith	625,000	Nil	3 years
Prent Kallenberger	625,000	Nil	3 years
William Sack	625,000	Nil	3 years

(ii) In January 2022, the Company provided unsecured three-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 2022 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.

30. 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	**2022 US$**	**2021 US$**
Financial assets at fair value		
Cash and cash equivalents	**14,087,032**	4,143,411
Trade and other receivables	**7,594,887**	4,377,779
Bonds and security deposits	**1,789,014**	1,931,556
	23,470,933	10,452,746
Financial liabilities at fair value		
Trade and other payables	**17,122,661**	2,022,359
Prepaid oil revenue	**11,000,000**	1,750,000
Derivative financial instruments	**–**	476,913
Insurance premium financing	**1,701,944**	1,530,593
Loans from related parties	**3,446,690**	3,578,780
Crescent promissory note	**4,830,114**	15,082,996
	38,101,409	24,441,641

(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 2022 financial year, no dividends were paid (2021: 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 material 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.

30. Financial instruments (continued)

(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$
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**	**–**	**–**	**–**
2021					
Non-interest bearing	–	4,021,044	98,937	83,956	180,398
Interest rate bearing bonds	0.5 to 1.0	–	–	–	1,925,000
Variable interest rate instruments	0.008	4,143,411	–	–	–

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$
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**	**–**
2021					
Non-interest bearing	–	2,073,251	187,564	238,457	–
Prepaid oil revenue	11.80	875,000	875,000	–	–
Fixed interest rate instruments	3.87	210,677	429,373	890,543	–
Related party liabilities	10.00	–	–	3,578,780	–
Crimson loan	15.00	626,500	1,479,700	7,336,432	5,640,364

(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) holdings in unlisted shares are measured at cost less any impairments. The directors consider that no other measure could be used reliably; and

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

(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 2022, 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$45,576 (2021: US$51,970) for an increase of 50 basis points; conversely a decrease of 50 basis points would result in a decrease of US$45,576 (2021: US$51,970) 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	**2022 $**	**2021 $**	**2022 $**	**2021 $**
USA currency denominated	**23,338,897**	10,202,416	**36,450,522**	22,698,195
Australian currency denominated	**191,663**	332,974	**2,396,410**	2,319,031

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	**2022 US$**	**2021 US$**
Profit or equity	**482,504**	1,123,783

(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. Changes in the fair value of these derivatives are 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$1,953,170 (2021: US$1,433,769) 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$1,953,170 (2021: US$1,433,769) to the net profit.

31. 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$127,202,217 (2021: US$104,193,107) and Australia US$6,122 (2021: US$7,036).

32. Interests in joint operations

As at 30 June 2022, 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; and

(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.

33. Parent entity information

Financial position	2022 US$	2021 US$
Assets		
Current assets	**89,972**	87,972
Non-current assets	**126,799,158**	135,031,802
Total assets	**126,889,130**	135,119,774
Liabilities		
Current liabilities	**3,579,017**	3,679,922
Total liabilities	**3,579,017**	3,679,922
Net assets	**123,310,113**	131,439,852
Equity		
Issued capital	**138,453,327**	138,429,568
Accumulated losses	**(13,999,564)**	(11,613,751)
Foreign currency translation reserve	**(7,169,901)**	197,249
Share option reserve	**6,026,251**	4,426,786
Total equity	**123,310,113**	131,439,852
Financial performance		
Profit/(Loss) for the year	**(2,385,813)**	(1,018,238)
Other comprehensive income/(loss)	**(7,367,150)**	7,750,753
Total comprehensive profit/(loss) for the financial year	**(9,752,963)**	6,732,515

Expenditure commitments

The parent entity has no expenditure commitments at the end of the 2022 financial year (2021: nil).

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 2022 (2021: nil), other than those listed in note 24 – Contingent liabilities.

34. Subsequent events

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

(i) on 7 July 2022 and 10 August 2022, Byron announced to the ASX that SM58 G3 and G5 wells commenced production of oil and gas from the SM58 G Platform;

(ii) on 10 August 2022, Byron announced that (a) Byron's net daily production had reached 2,332 bopd and 7,154 mcf; (b) the SM71 F2 well commenced production from the J1 Sand recompletion; and (c) SM71 F4 well was also recompleted to the J1 Sand and was being brought online; and

(iii) on 14 September 2022, Byron released its 2022 reserves and resources report.

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 Battersby
Chairman

30 September 2022

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 consolidated 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 2022, 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:

(i) giving a true and fair view of the Group's financial position as at 30 June 2022 and of its financial performance for the year then ended; and

(ii) 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.

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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 of 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.

Key Audit Matters	How the scope of our audit responded to the Key Audit Matters
Amortisation of Oil and Gas properties For the year ended 30 June 2022 the Group amortised US$11.6 million of oil and gas properties as disclosed in Note 8(b). When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a unit of production of 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.	Our audit procedures included, but were not limited to: • 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; and • Recalculating the mathematical accuracy of the amortisation recognised. We also assessed the appropriateness of the disclosures in Note 8 to the financial statements.

Other Information

The directors are responsible for other information disclosed. The other information comprises the information included in the Group's annual report for the year ended 30 June 2022 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 of the Company 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.

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.

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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 director's 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.

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From the matters communicated with 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.

Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 40 to 44 of the Directors' Report for the year ended 30 June 2022.

In our opinion, the Remuneration Report of Byron Energy Limited, for the year ended 30 June 2022, 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

Craig Bryan
Partner
Chartered Accountants
Melbourne, 30 September 2022

ASX Additional Information

Additional information required by the Australian Securities Exchange Ltd Listing Rules and not disclosed elsewhere in this report is as follows. The information is current as at 4 October 2022.

Distribution of equity securities

As at 4 October 2022, 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 5,237 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 two option-holders exercisable on or before 31 December 2024 at an exercise price of A$0.16 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	1,017	405,933
1,001 – 5,000	1,222	3,362,288
5,001 – 10,000	668	5,059,175
10,001 – 100,000	1,500	55,906,860
100,001 and over	830	1,016,660,846
Total holders	**5,237**	**1,081,395,102**

The number of security investors holding less than a marketable parcel of securities is 649 with a combined total of 144,443 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

In January 2022 Byron issued 41,100,000 new shares to key management personnel, other senior staff and consultants following exercise of 41,100,000 unlisted options, funded by an unsecured 3 year interest free loans , commencing on 31 December 2021, from the Company to the option holders ("Loan Funded Shares"). The interest free loans ("Option Exercise Loans") were approved by shareholders at the Company's 2021 annual general meeting held on 29 November 2021.

Loan Funded Shares are subject to voluntary escrow arrangements in accordance with the Voluntary Escrow Deed. These shares are already quoted on the ASX and have the same rights as all other ordinary shares issued by Byron, except they are placed in trading lock. The Loan Funded Shares are held by executive directors, staff and contractors of the Company.

ASX Additional Information continued

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)	57,300,568	5.30%

20 Largest Shareholders

Top 20 holdings as at 04.10.2022

Byron Energy Limited

Fully paid ordinary shares

	Name	Balance	%
1	BNP PARIBAS NOMINEES PTY LTD <IB AU NOMS RETAILCLIENT DRP>	71,534,305	6.62
2	VERUSE PTY LIMITED	44,435,985	4.11
3	J & A VAUGHAN SUPER PTY LTD <J & A VAUGHAN SUPER A/C>	34,510,066	3.19
4	ELMSLIE SUPERANNUATION COMPANY PTY LTD <ELMSLIE FAMILY S/F A/C>	28,269,844	2.61
5	GEOGENY PTY LTD <M AND V SMITH SUPER A/C>	32,627,836	3.02
6	MR CHARLES SANDS	20,382,409	1.88
7	WALLEROO PTY LTD	18,828,791	1.74
8	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	15,275,783	1.41
9	CLAPSY PTY LTD <BARON SUPER FUND A/C>	13,854,350	1.28
10	GEOGENY PTY LIMITED	13,214,045	1.22
11	CITICORP NOMINEES PTY LIMITED	12,811,168	1.18
12	BARRIJAG INVESTMENTS PTY LIMITED	12,645,000	1.17
13	MR JOHN SANDS <THE JOHN SANDS REVOCABLE A/C>	12,080,972	1.12
14	AGRICO PTY LTD <PALM SUPER FUND A/C>	11,446,384	1.06
15	POAL PTY LTD <BARAIN SUPER FUND A/C>	11,341,298	1.05
16	FITZROY RIVER CORPORATION LIMITED	11,210,089	1.04
17	JETAN PTY LTD	10,550,001	0.98
18	DIXSON TRUST PTY LIMITED	9,788,400	0.91
20	BATTERSBY PTY LTD <VERUSE EMPLOYEES S/F A/C>	9,295,959	0.86
Total securities of top 20 holdings		**414,392,685**	**38.32**
Total of securities		**1,080,395,102**	

Corporate Directory

Directors

Doug Battersby (Non-Executive Chairman)
Maynard Smith (Executive Director and 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

Registered and Principal Australian Office

Level 4
480 Collins Street
MELBOURNE VIC 3000

Principal Office (USA)

Suite 100
425 Settlers Trace Boulevard
LAFAYETTE LA 70508

Legal Adviser

Piper Alderman
Level 23, Governor Macquarie Tower
1 Farrer Place
SYDNEY NSW 2000

Auditors

Deloitte Touche Tohmatsu
477 Collins Street
MELBOURNE VIC 3000

Website

www.byronenergy.com.au

Home Stock Exchange

ASX Limited
20 Bridge Street
SYDNEY NSW 2000
ASX Code: BYE

Share Registry

Boardroom Pty Limited
Grosvenor Place, Level 12, 225 George Street
SYDNEY NSW 2000
Tel: 1300 737 760
Fax: 1300 653 459

BYRONENERGY