BYRONENERGY

Annual Report 2026

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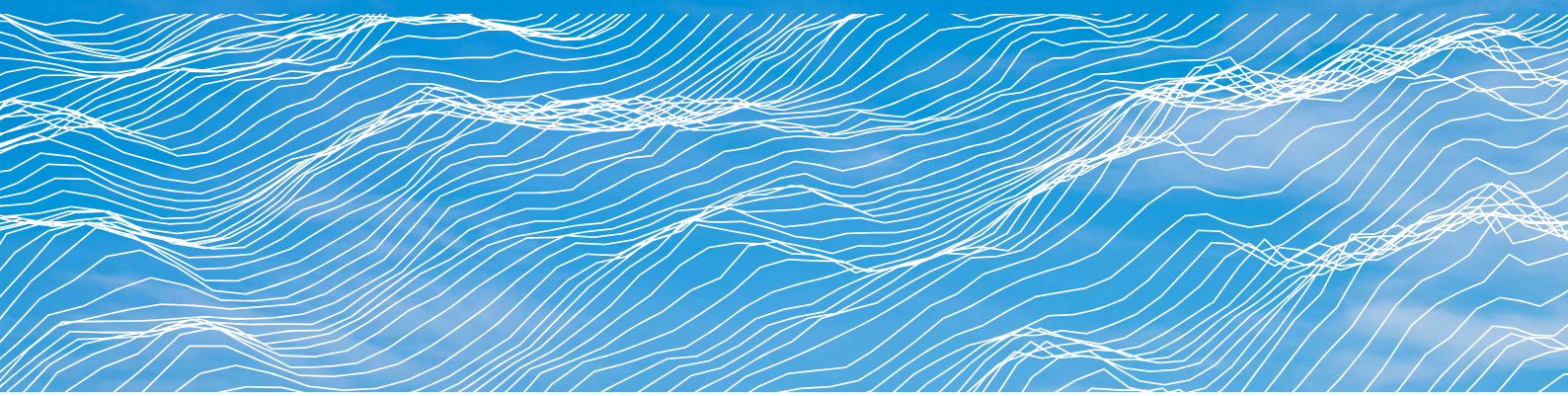
BYRON ENERGY IS AN INDEPENDENT OIL AND GAS EXPLORATION AND PRODUCTION COMPANY, HEADQUARTERED IN AUSTRALIA, WITH OPERATIONS IN THE SHALLOW WATER OFFSHORE LOUISIANA IN THE GULF OF MEXICO.



Highlights

SM58 Production
(including E2 well)

964 Bopd

Production (gross)

Average daily production of approximately 964 bopd and 0.8 Mmcfd for 2026

SM71 Production

727 Bopd

Production (gross)

Average daily production of approximately 727 bopd and 0.2 Mmcfd for 2026

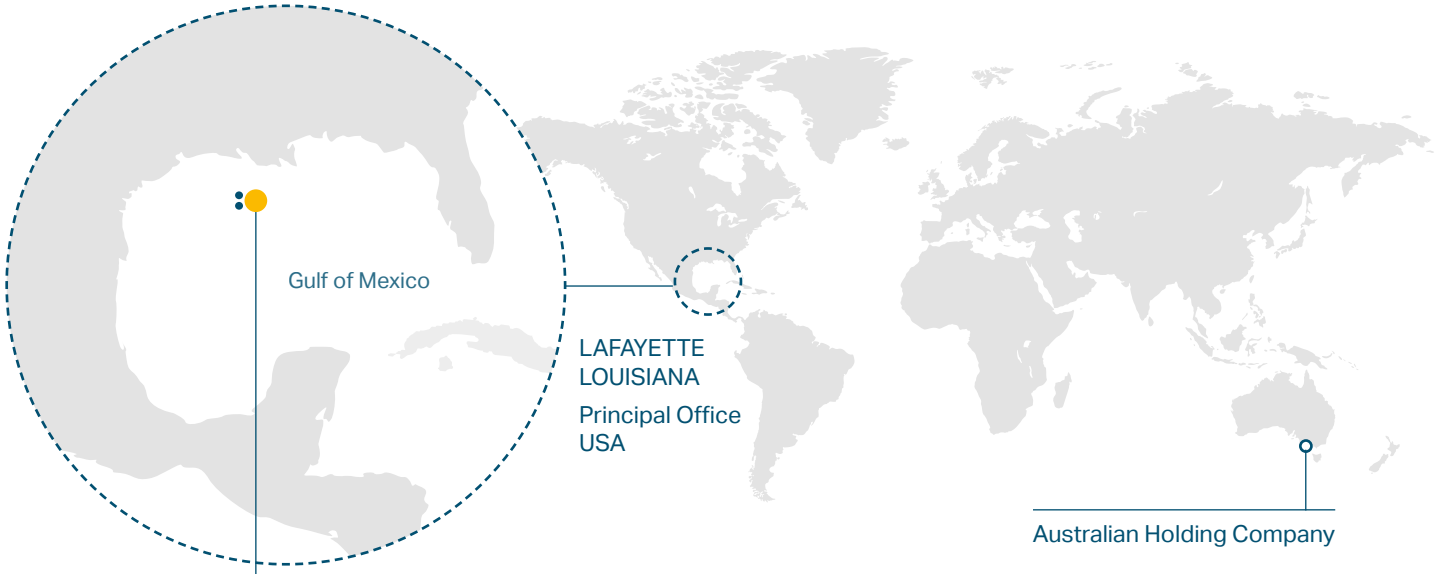
Company Wide Reserves
(Net)

2P 13.6 MMboe

Reserves

2P (net) 9.3 MMbo
2P (net) 26.2 Bcfg
2P (net) 13.6 MMboe

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
- Exploration Blocks

Chairman's Letter

Dear Shareholder,

The 2026 financial year was an improvement on 2025 with an improved balance sheet and with revenue benefiting from a significant recovery in oil prices in the second half of the year, as a consequence of geopolitical conflicts in the Middle East.

The 2026 financial year started with a liquidity squeeze, due to the cost overruns incurred while drilling the SM71 F5ST and BP1 wells in late 2024.

Through a combination of management focus on production efficiency, greater cost discipline and coupled with higher oil prices, Byron has managed to:

Repay all vendors, who performed work on the SM71 F5 well, by end of the March 2026 quarter, nine months ahead of the original schedule.

Repay the oil revenue prepayment facility on schedule.

Commence repayment of the directors' loan in April 2026, in line with the loan agreement.

Our net revenue and cash from operations were boosted by both improved production efficiency and the increase in oil prices from the end of February 2026 because of the US/Iran geopolitical conflict, which is still ongoing. The average realised oil price over the six months to 30 June 2026 was significantly above the prices realised for the first half of the financial year.

For the full 2026 financial year, Byron realised an average oil price, before transport charges, of US$73.61 per barrel (US$74.90 for the 2025 year). However, the average oil price, before transport charges, realised in the second half of the 2026 financial year was US$83.29 per barrel, an increase of nearly 28% over the average realised price for the first half of the 2026 financial year.

Between July 2025 and mid October 2026, West Texas Intermediate (WTI) crude oil price rose from $65.52 per barrel to a high of $105.83 per barrel in mid September 2026, before settling around US$95.00 by mid October 2026. Oil prices aggressively accelerated in late August and early September specifically due to mounting attacks on Saudi Arabian energy infrastructure and intense shipping restrictions through the Strait of Hormuz, triggering extreme concern regarding global oil supply.

Realised gas prices were relatively flat for the year. In 2026 Byron realised an average gas price of US$3.54 per mmbtu, before transport charges compared to US$3.59 per mmbtu in 2025.

Between July 2025 and early October 2026, the Henry Hub natural gas spot price experienced significant volatility, highlighted by a dramatic winter surge followed by a downward correction driven by record-high U.S. inventory levels. Over the whole period the price trended slightly downward from around $3.20/MMBtu down to $2.88/MMBtu.

During the 2026 financial year our focus remained on maximisation of oil production and cash generation. Downtime on both Byron-operated platforms was reduced, compared to the previous year, following several decisions taken by management to improve operational efficiency.

As first reported in the September 2025 quarterly report, Byron commenced a process to actively explore all possible options to deliver the best possible value outcome for shareholders. As part of this process, Byron engaged a London-based specialist firm that acts as a critical partner to clients engaged in the energy sector across corporate finance, asset management, and financial advisory.

Over the last year a number of parties signed confidentiality agreements to access the virtual data room established by Byron in conjunction with its London-based advisory firm. Byron and the advisory firm have engaged with several parties evaluating the potential participation in the recapitalisation of Byron. Two parties substantially completed their due diligence however we could not agree on acceptable commercial terms with either.

While higher oil prices have been beneficial over the last six months, the extreme oil price volatility being experienced and the uncertainty about the timing of the resolution of the current Middle East geopolitical issues and the price levels post resolution has made it more difficult to value, and negotiate transactions because buyers and sellers cannot agree on whether high oil prices are a permanent structural shift or a temporary geopolitical spike. While the current process to explore options to deliver the best possible value outcome for shareholders has now concluded, Byron will re-focus on realising value through ongoing oil and gas exploration and production in the Gulf of Mexico while maintaining an opportunistic stance regarding recapitalisation or asset monetisation opportunities.

Once again, I thank our management team, employees and contractors who continue to maintain an excellent safety and environmental record and focus on maximisation of oil production and cost control to enable the Company to further capitalise on higher oil prices in 2026.

I also thank our non-executive directors for their continued support and guidance and our fellow shareholders for their understanding and patience. As previously stated, shareholders can be assured that as major shareholders of Byron, with just over 15% of the shares, our interests are totally aligned with the interests of all shareholders, and that we will continue to focus on the optimisation of the value of our equity.

Doug Battersby
Chairman

14 October 2026

Review of Operations

Highlights for the year ended 30 June 2026 included:

- Net Proved Reserves (1P) of 5.4 MMbo and 22.3 Bcfg, (9.2 MMboe), an increase of approximately 12% compared to 2025, mainly due to an upward revision of SM58 proved undeveloped reserves partly offset by production for the year;
- Net Proved and Probable Reserves (2P) of 9.3 MMbo and 26.2 Bcfg (13.6 MMboe) an increase of approximately 7% over 2025;
- Net production (sales) for the year ended 30 June 2026 was 392,951 barrels of oil and 306,695 mmbtu of gas compared to 376,973 barrels of oil and 847,573 mmbtu of gas for the year ended 30 June 2025;
- Net sale revenue of US$27.6 million for 2026 compared to US$29.1 million in 2025;
- Earnings before interest, tax, amortisation, impairment, realised oil hedge price gains/losses and depreciation and exploration expense (EBITDAX) for the year ended 30 June 2026 totalled US$14.1 million compared to US$14.9 million for the year ended 30 June 2025; and
- Lease Operating Expenses, excluding amortisation, of approximately US$20.56/boe in 2026, (US$18.60/boe in 2025).

Net Proved Reserves (1P) of

5.4 MMbo

22.3 Bcfg

(9.2 MMboe)

an increase of approximately 12% over 2025

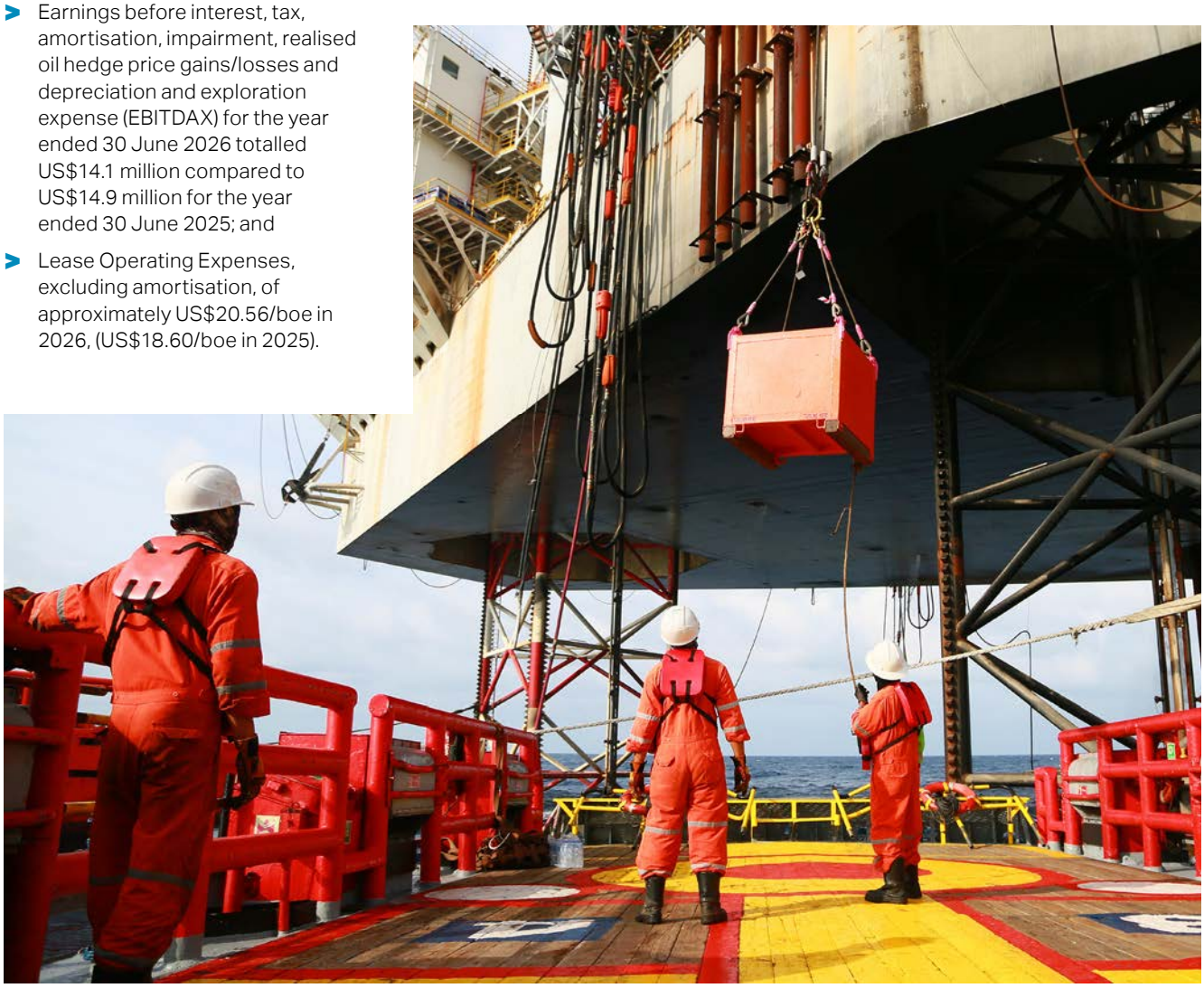
Net Proved and Probable Reserves (2P) of

9.3 MMbo

26.2 Bcfg

(13.6 MMboe)

an increase of approximately 7% over 2025



Review of Operations continued

Production for the year ended 30 June 2026 was approximately 392,951 bbls of oil and over 0.30 bcf of gas, net to Byron, generating net sales revenue of approximately US$27.6 million. Because of higher oil prices experienced in the second half of the financial year Byron recorded higher net revenue in the second half of the 2026 financial year notwithstanding lower oil production.

	6 Months to 31 December 2025	6 Months to 30 June 2026	12 Months to 30 June 2026	12 Months to 30 June 2025
Average realised oil price pre transport (US$/barrel)*	**65.32**	**83.29**	**73.61**	74.90
Average realised oil price post transport (US$/barrel)*	**59.19**	**77.17**	**67.49**	69.03
Average realised gas price before transport (US$/mmbtu)	**3.45**	**3.68**	**3.54**	3.59
Average realised gas price post transport (US$/mmbtu)	**3.10**	**3.40**	**3.22**	3.23
Oil production (net to Byron (barrels)	**211,668**	**181,283**	**392,951**	**376,973**
Gas production/sales (net to Byron (mmbtu)	**187,209**	**119,486**	**306,695**	**847,573**
Net Revenue (US$ million)	**13.2**	**14.4**	**27.6**	**29.1**
EBITDAX (US$ million)	**6.5**	**7.6**	**14.1**	**14.9**

* Including oil price hedges.

Byron's Proved Reserves (1P) were 5.5 Mmbo of oil and 22.3 Bcf of gas as at 30 June 2026 and Proved and Probable Reserves (2P) were 9.3 Mmbo of oil and 26.2 Bcf of gas.

Net Remaining Reserves as at 30 June 2026*	Oil (Mmbo)	Gas (Bcf)	Mmboe (6:1)
Proved	**5.4**	**22.3**	**9.2**
Probable	3.8	3.8	4.4
Proved and probable (2P)	**9.3**	**26.2**	**13.6**
Possible	4.9	5.3	5.8
Proved, Probable and Possible (3P)	**14.2**	**31.4**	**19.4**
Prospective Resources	**16.9**	**97.3**	**33.1**

* For further information on reserves refer to page 15 in the Review of Operations.

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

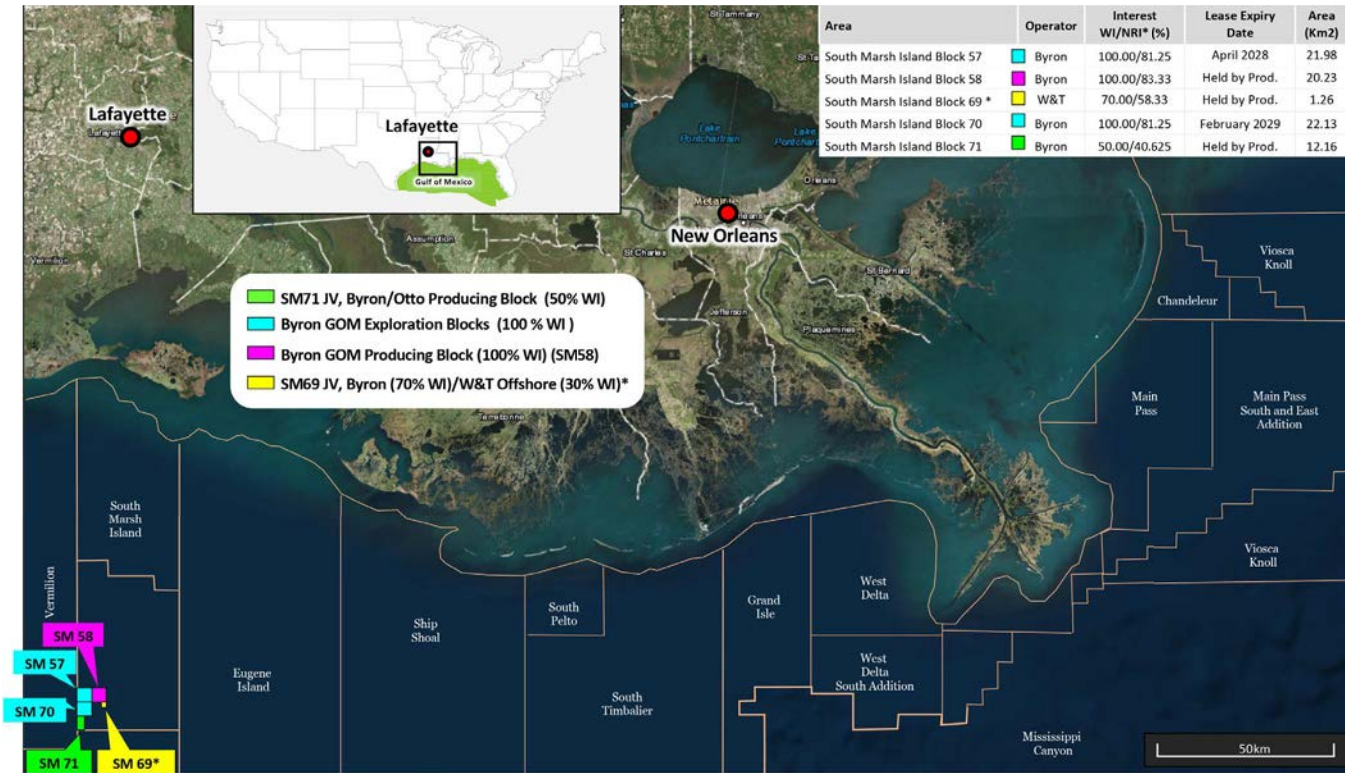
Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

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

Oil and Gas Properties

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

Byron Energy Gulf of Mexico Lease Map as at 30 June 2026



Area	Operator	Interest WI/NRI* (%)	Lease Expiry Date	Area (Km2)
South Marsh Island Block 57	Byron	100.00/81.25	April 2028	21.98
South Marsh Island Block 58	Byron	100.00/83.33	Held by Prod.	20.23
South Marsh Island Block 69 *	W&T	70.00/58.33	Held by Prod.	1.26
South Marsh Island Block 70	Byron	100.00/81.25	February 2029	22.13
South Marsh Island Block 71	Byron	50.00/40.625	Held by Prod.	12.16

* SM69 E2 well 70% WI/58.33% NRI; SM69 E Platform and E1 well 53% WI and 44.17% NRI.

Review of Operations continued

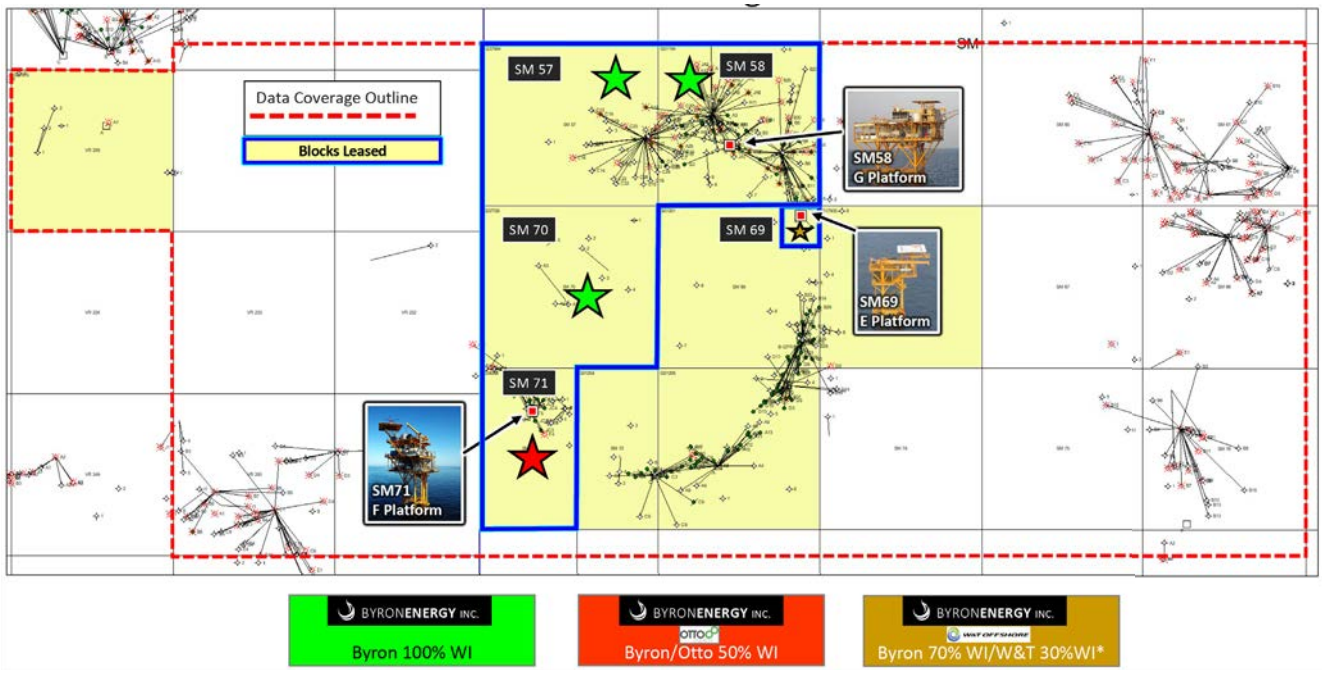
1. South Marsh Island 73 Salt Dome

The SM73 field encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 feet to 8,800 feet Total Vertical Depth. Most 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 6 areas of interest around the SM73 field, comprising SM 57/58/60/61/66/70. Byron is also the operator of SM71, where it has a 50% working interest. In addition, Byron holds a non-operated interest in the SM58 E1 well and SM69 E platform in the NE ¼ of NE ¼ of SM69).

Byron has conducted a 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)

Water depth in the area is approximately 137 feet.

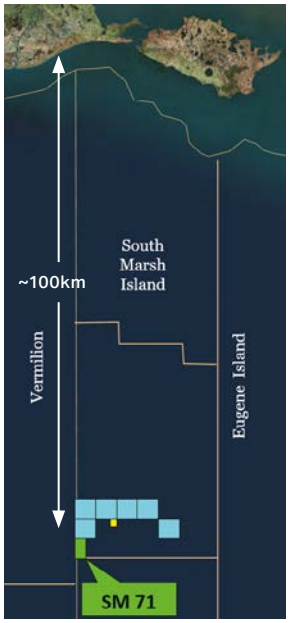
Oil and gas production from the Byron operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well commenced production in mid-March 2020.

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

As of 30 June 2026, the SM71 F facility has produced approximately 5.5 Mmbo (gross) since initial production began. The facility has also produced approximately 6.3 Bcfg) (gross).

South Marsh Island 71 (SM71) Project Summary

Working Interest Holders	Byron Energy 50% Otto Energy 50%
Operator	**Byron Energy Inc.**
Water Depth	40 meters (131')
Previous SM71 Production	3.9 mmbo + 10 bcf (1995 to 2010)
Acquired	OCS Sale 222 June 2012 for US$166,620
Byron Interest	50% WI, 40.625% NRI
Byron #1 (F1) discovery well (followed by F2 and F3)	April 2016, 132' TVT NFO
F Platform Installation Completed	October 2017
Initial Production (Three Wells) F1, F2 and F3	F1 first prod. March 2018 F2 and F3 first prod. April 2018 F4 first prod. March 2020
SM71 Total Gross Oil and Gas Produced from March 2018 to June 2026	5.5 mmbo + 6.3 Bcf
Net 2P Remaining Reserves*	1.3 mmbo + 1.1 bcf



SM71 Reserve Summary*	Gross Reserves Remaining 30/6/26		Net Reserves Remaining 30/6/26	
	mbo	**mmcf**	**mbo**	**mmcf**
1P Proved	**2,078**	**1,628**	**847**	**662**
Probable	1,215	966	493	392
2P	**3,293**	**2,594**	**1,340**	**1,054**
Possible	2,804	1,912	1,139	777
3P	**6,097**	**4,506**	**2,479**	**1,831**
	Gross Prospective Resource		**Net Prospective Resource**	
Prospective	**3,709**	**43,114**	**1,507**	**17,515**

* Collarini and Associates reserves report as at 30th June 2026; refer Company release dated 1 September 2026 at www.byronenergy.com.au

Review of Operations continued

SM71 Project Status

Byron's share of SM 71 production for the year ended 30 June 2026, compared to 2025 year, is shown in the table below.

Production (Sales)	Year Ended 30 June 2026	Year Ended 30 June 2025
Gross production		
Oil (bbls)	**265,435**	261,309
Gas (mmbtu)	**86,603**	408,803
Byron share of gross production (WI basis)		
Oil (bbls)	**138,872**	132,590
Gas (mmbtu)	**44,614**	205,202
Net production (NRI basis)		
Oil (bbls)	**112,833**	107,729
Gas (mmbtu)	**36,249**	166,727

Oil production for the year ended 30 June 2026 was slightly above the volumes achieved for the 2025 year, mainly due to higher production from the F4 well partly offset by lower production from the F1 well. The main producer, the up-dip SM71 F1 well, continues to produce water free with the rate managed to optimise the D5 Sand reservoir's oil production.

Byron's share of net revenue, after royalties, oil transportation charges and other customary price adjustment, for the 2026 year from SM71 of approximately US$7.6 million was approximately 7% below US$8.2 million for the 2025 year. Lease operating expenses, excluding amortisation and depreciation, for the 2026 year were US$2.5 million, flat compared to the 2025 year.

As of 30 June 2026, Collarini assigned proved reserves (net to Byron) of 0.8 Mmbbo and 0.7 Bcf and 2P reserves (net to Byron) of 1.3 Mmbbl and 1.1 Bcf to SM71.

During the year ended 30 June 2026, there was no drilling or development activities with the focus on optimising oil production from The SM71 F platform.

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

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

Byron earned a 100% WI in the SM69 E2 well (E2) under the Joint Exploration Agreement (JEA) with ANKOR group (now WT Offshore Inc). By funding 100% of the E2 well, Byron earned a 100% WI and 80.33% NRI until E2 Project Payout. Effective 1st January 2023, Byron's 100% WI and 80.33% NRI in the SM69 E2 well was reduced to 70% WI with an unburdened 58.33% NRI, after WT Offshore exercised its option to convert its overriding royalty interest into a 30% WI, 25% NRI in the E2 well.

As of 30 June 2026, the SM58 G facility has produced approximately 10.5 Bcfg and 1.9 million barrels of oil and condensate (gross) on a cumulative basis from seven wells (SM58 G1, G2, G3, G4, G5, G6 and SM69 E2 wells).

The SM58 G wells are currently producing from the following sands:

(i) G1 well produces from the Upper O Sand;

(ii) G2 ST from the O Sand:

(iii) G3 from the J Sand;

(iv) G4 from the K4 Sand;

(v) G5 from the K4 Sand; and

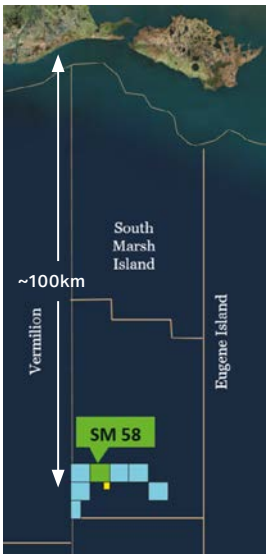
(vi) G6 from the L2 Sand,

During the year ended 30 June 2026 there was no drilling or development activity at SM58. The focus at SM58 G platform during the year was on optimisation of oil production. A number of specific optimisation techniques including re-design of the gas-lift in the E2 well, paraffin soaks vs cutting in the SM58 G1 well to save money with similar outcome and chemical studies to minimize downtimes while also keeping the wellbores free of paraffin were implemented in the June 2025 quarter and continued to benefit the Company in the 2026 year.

Production of oil, gas and any other liquids from the E2 well, located on SM69 E platform, flows to the Byron operated SM58 G platform where separation occurs before oil and gas are sent to sales pipelines. Under the JEA, Byron will continue to process the production at SM58 G Facility on behalf of the joint interest under a production handling agreement with the non-operating partner paying Byron for the processing and transportation of production.

South Marsh Island 58 Project Summary

Working Interest Holder(s)	Byron Energy
Operator	Byron Energy Inc.
Water Depth	~37 meters (121')
Previous SM58 Production	35.8 mmbo + 265 bcf
Acquired Jan 1st 2019 from Fieldwood Energy	US$4,250,000
Byron Interest	100% WI, 83.33% NRI*
Byron #1 (G1) discovery well	September 2019, 301' TVT Hydrocarbon Pay
SM58 G Platform – Installation Completed and Installed	July 2020
Initial production	G1/G2 Sept/Nov 2020 E2 first production October 2021* G3/G5 July/August 2022 G4/G6 Dec 2023 quarter
SM58 G platform Total Gross Oil and Gas Produced from September 2020 to June 2026 (including SM69E 2 well)	10.5 BCF and 1.9 mmbo
G Platform Capacity	9 slot platform with 8,000 bopd + 80 mmcfgpd +8,000 bwpd
Net 2P Remaining Reserves 30/6/2026 – SM58 (including E2 well)	7,378 mbo + 24,229 mmcf**



SM58 (Including E2 Well) Reserve Summary#	Gross Reserves Remaining 30/6/26		Net Reserves Remaining 30/6/26	
	mbo	mmcf	mbo	mmcf
1P Proved	**5,060**	**24,834**	**4,080**	**20,813**
Probable	3,957	4,099	3,298	3,416
2P	**9,017**	**28,933**	**7,378**	**24,229**
Possible	4,515	5,387	3,762	4,489
3P	**13,532**	**34,320**	**11,140**	**28,718**
	Gross Prospective Resource		**Net Prospective Resource**	
Prospective	**14,241**	**58,192**	**11,903**	**49,031**

* 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.

** Includes SM58 SM69 E2 net 2P remaining reserves.

Collarini and Associates reserves report as at 30th June 2026; refer Company release 1 September 2026 at www.byronenergy.com.au

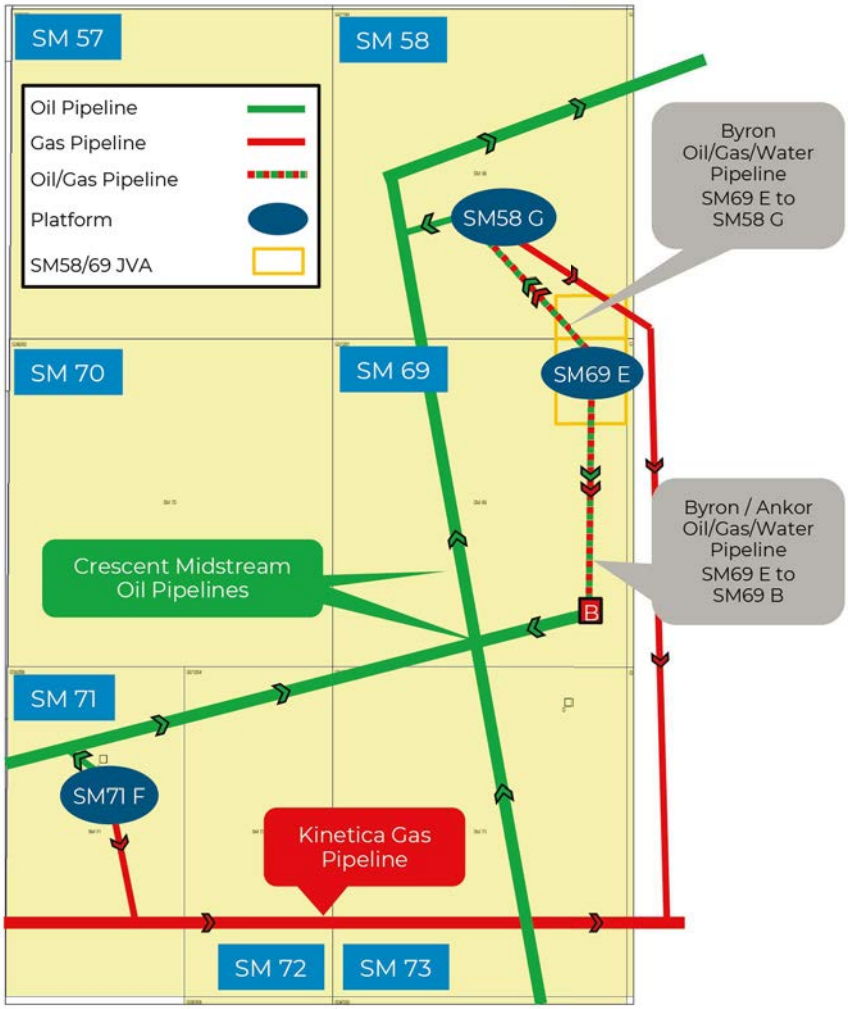
Review of Operations continued

SM58 Project Status

Byron's share of SM 58 production for the year ended 30 June 2026, compared to 2025 year, is shown in the table below.

Production (Sales)	Year Ended 30 June 2026	Year Ended 30 June 2025
Gross production		
Oil (bbls)	**354,087**	359,495
Gas (mmbtu)	**332,136**	831,708
Byron share of gross production (WI basis)		
Oil (bbls)	**323,259**	315,010
Gas (mmbtu)	**324,145**	816,228
Net production (NRI basis)		
Oil (bbls)	**269,381**	262,507
Gas (mmbtu)	**270,120**	680,187

Byron Pipelines Schematic



Oil production for the year ended 30 June 2026 was marginally below the volumes achieved for the 2025 year, mainly due to lower production from SM58 G1, G3, G4 and SM69 E2 wells partly offset by higher production from the SM58 G6 BP01 well (G6). In the 2026 year, Byron benefited from a full year's production from the L2 Sand in the G6 well with Byron having changed zones, in January 2025, in the G6 well from the N2 Sand which was producing at less than 50 bopd to the L2 Sand, the primary target of the G6 well. The G6 well continues to be managed to protect the sand control completion and ensure that no damage occurs to the sand control screens. As of 30 June 2026, the G6 was producing approximately 290 bopd, 200 barrels of water per day (bwpd) with a small amount of gas with water production having commenced at the end of March 2026. The water cut appears to have stabilised increasing confidence that the oil reserves attributed to the L2 sand will still be produced but at lower rate (over a longer period).

For the year ended 30 June 2026, Byron's share of net revenue from SM58 after royalties, and oil transportation charges and other customary price adjustments was US$19.2 million compared to US$20.4 million for the 2025-year. Lease operating expenses (excluding depreciation and amortisation) were US$5.8 million for the 2026 year (2025 US$6.2 million) reflecting management's efforts through the year to manage down cash operating expenses.

As of 30 June 2026, Collarini has assigned proved reserves (net to Byron) of 4.1 Mmbbo and 20.8 Bcf and 2P reserves (net to Byron) of 7.4 Mmbbo and 24.2 Bcf to SM58 (including E2 well).

(c) SM 58E1/69E Platform

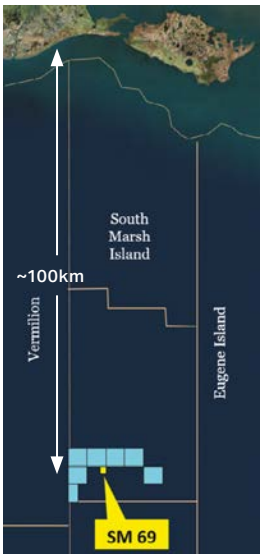
Byron owns a 53% WI and a 44.17% NRI in the joint area reservoirs from the surface to a depth of 7,490 feet TVD, located in the S1/2 of the SE1/4 of the SE1/4 of SM58, as well as a 53% working interest in the SM 69 E platform. W&T Offshore Inc (as successor to Ankor Energy, LLC) is the designated operator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

The SM58 E1 well produces from the K Sand.

While the SM 69 E2 well (referred to above) is located on the SM 69 E platform, Byron produce the SM69E2 well back to the SM58 G platform through a flowline laid in July 2020. Hydrocarbons from the E2 well are processed and sold through the SM58 G Platform.

South Marsh Island 69 (SM58 E1 and SM69 E2) Project Summary

Working Interest Holder(s)	Byron Energy
Operator SM69 E2 well Operator SM58 E1/SM69 E Platform	Byron Energy Inc. W&T Offshore
Water Depth	38 meters (125')
Previous SM58 Production (prior to Byron purchase)	35.8 mmbo + 265 bcf
Acquired SM58 E1/SM69 E Platform Jan 1st 2019 from Fieldwood Energy; Farmed into SM69 E2 via JEA with ANKOR (now W&T Offshore)	US$4.85 million 100% WI/83.33% NRI for funding 100% of SM69 E2 well
SM69 E Platform Installation Completed and Installed in 2013	SM69 E1 well produced off SM69E platform and flows to W&T Offshore SM69 B operated platform
Byron SM69E2 discovery well	Drilled September 2021, 81' TVT Hydrocarbon Pay, from SM69 E platform and produced back to SM58 G platform through pipeline laid in 2020; commenced production in October 2021
Net 2P Remaining Reserves*	547 mbo + 879 mmcf (excluding E2 well reserves which are included with SM58)



SM58E1/SM69E Platform Reserve Summary*	Gross Reserves Remaining 30/6/26		Net Reserves Remaining 30/6/26	
	mbo	mmcf	mbo	mmcf
1P Proved	**1,179**	**1,970**	**521**	**869**
Probable	59	23	26	106
2P	**1,238**	**1,993**	**547**	**879**
Possible	–	–	–	–
3P	**1,238**	**1,993**	**547**	**879**
	Gross Prospective Resources		**Net Prospective Resources**	
Prospective	**856**	**857**	**513**	**513**

* Collarini and Associates reserves report as at 30th June 2025; refer Company release 1 September 2026 at www.byronenergy.com.au

Review of Operations continued

SM69 Project Status

Byron's share of production (excluding E2 well) for the year ended 30 June 2026 is shown in the table below.

Production (Sales)	Year Ended 30 June 2026	Year Ended 30 June 2025
Gross production		
Oil (bbls)	**24,308**	15,253
Gas (mmbtu)	**738**	1,492
Byron share of Gross Production (WI basis)		
Oil (bbls)	**12,883**	8,084
Gas (mmbtu)	**391**	791
Net production (NRI basis)		
Oil (bbls)	**10,737**	6,737
Gas (mmbtu)	**326**	659

Oil and gas production for the year ended 30 June 2026 was above the volumes achieved for the 2025 year mainly due to the operator's actions to operate the SM69 E1 well at higher production rates. Under an agreement between Byron and W&T Byron sells excess gas from the SM58G platform to the SM69E platform, delivered to SM69E platform through Byron's 100% owned gas lift pipeline providing W&T with field use gas which allows W&T to operate its SM72 field more efficiently and in turn operate the SM69 E1 well at higher oil production levels. Byron benefits from both the incremental transport revenue and more consistent E1 oil production.

For the year ended 30 June 2026, Byron's share of net revenue from SM58 E1 well was approximately US$0.8 million compared to US$0.5 million for the 2025 year, due to higher production.

Collarini has assigned 2P reserves (net to Byron) of 0.5 Mmbbo and 0.9 Bcf to the developed and undeveloped reserves in S ½ of SE ¼ of SE ¼ of SM58 and the NE ¼ of NE ¼ of SM69, excluding the E2 well, as at 30 June 2026.

South Marsh Island Area Exploration and Evaluation Assets

During the 2026 year, Byron continued to closely monitor its portfolio of exploration and evaluation leases.

As foreshadowed in the June 2025 annual report, the SM61 lease was relinquished during the September 2025 quarter. The carrying value of the SM61 lease was reduced to zero in the 30 June 2025 financial report. Byron was the high bidder on South Marsh Island Block 57 at OCS Lease Sale Big Beautiful Gulf 1 (BBG1) held in New Orleans on 10 December 2025.

Byron's bid amount was US$143,948 (US$26.50 per acre) for the SM57 lease. A high bid is subject to a review of bid adequacy by the Bureau of Ocean Energy Management (BOEM) and may be rejected if deemed inadequate. In January 2026, Byron was formally awarded the SM57 lease. Byron previously relinquished the SM57 lease in April 2025. By relinquishing and re-bidding Byron saved one annual advance rental and extended the lease term by nearly 4 years with the Net Revenue Interest increasing from 81.25% to 87.5% under the new lease.

South Marsh Island 57/70

As of 30 June 2026, Byron holds two leases in the vicinity of the Company's SM58 G platform, Byron holds a 100% WI and an 87.25% NRI in South Marsh Island 57 (SM 57) and a 100% WI and an 81.250% NRI in South Marsh Island 70 (SM 70).

SM57 and SM70 blocks were part of the seismic processing project, which Byron undertook with Schlumberger's subsidiary WesternGeco to help evaluate potential future exploration drill sites.

Properties

As at 30 June 2026, Byron's portfolio of properties, all in the shallow waters of the Gulf of Mexico, USA comprised:

Properties	Operator	Interest WI/ NRI (%)*	Lease Expiry Date	Lease Area (Km²)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/87.50	January 2031	21.98
Block 70	Byron	100.00/81.25	March 2029	22.13
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	53.00/44.16667		
SM69 (NE ¼ of NE ¼) (E-2 well)	Byron	70.00/58.33	Production	1.30

* 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 TV.

Reserves and Resources

The Company's reserves and resources estimate as at 30 June 2026 was reported by Byron on 1 September 2026, with remaining proved reserves (1P) of 5.4 Mmbo l and 22.3 Bcfg and proved and probable reserves (2P) of 9.3 Mmbo l and 26.2 Bcfg.

The Company's 1P remaining reserves of 9.2 Mmboe as of 30 June 2026 increased by approximately 12% year on year, with proved developed reserves (producing and behind pipe) approximately 4% lower, reflecting production for the year ended 30 June 2026, and proved undeveloped reserves approximately 22% higher mainly due to an upward revision of SM58 proved undeveloped reserves.

Remaining 2P reserves of 13.6 Mmboe and 3P reserves of 19.4 Mmboe, as of 30 June 2026, increased by approximately 7% and 4% respectively.

The Company's Prospective Resources as of 30 June 2026 increased by approximately 8% year on year to 33.1 Mmboe, largely due to inclusion of SM57 resources. Byron acquired the SM57 lease at OCS Lease Sale Big Beautiful Gulf 1 (BBG1) held in New Orleans on 10 December 2025.

The combined remaining reserves and prospective resources, net to Byron, as of 30 June 2026 are as shown in the table below.

Byron Energy Limited – Reserves and Resources Total

Source: Collarini Associates Reserves and Resources Report

Reserve Category	Net to Byron		
June 30, 2026	**Oil Mbbl**	**Gas MMcf**	**Mboe (6:1)**
Proved producing	1,337	1,938	1,660
Proved behind pipe	1,155	1,551	1,414
Total proved developed	**2,492**	**3,489**	**3,074**
Proved undeveloped	2,957	18,855	6,100
Total proved (1P)	**5,449**	**22,344**	**9,174**
Probable incremental producing	280	112	299
Probable behind pipe	150	169	178
Total probable developed	**430**	**281**	**477**
Probable undeveloped	3,387	3,537	3,977
Total probable	**3,817**	**3,818**	**4,454**
Total proved and probable (2P)	**9,266**	**26,162**	**13,628**
Total possible	4,902	5,266	5,779
Proved,probable + possible (3P)	**14,168**	**31,428**	**19,407**
Prospective Resources Unrisked (Pr)	**16,875**	**97,335**	**33,098**

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

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

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

Developed reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed producing reserves are reserves expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Developed behind-pipe reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Review of Operations continued

Notes to Reserves and Resources Statement

Reserves and Resources Governance

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

Competent Persons Statement

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

Reserves Cautionary Statement

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

Prospective Resources Cautionary Statement

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

Forward Looking Statements

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

Financial Report

For the Year Ended 30 June 2026

Directors' Report

The directors of Byron Energy Limited, submit herewith the annual report of the Group for the financial year ended 30 June 2026. In order to comply with the provisions of the *Corporations Act 2001*, the directors report as follows:

For the purposes of this Directors' Report, the terms "Company" refers to Byron Energy Limited and "Byron", "Group" and "Consolidated Entity" refer to Byron Energy Limited and its consolidated entities.

Directors

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

Douglas G. Battersby

Maynard V. Smith

Prent H. Kallenberger

Charles J. Sands

Paul A. Young

William R. Sack

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

Names, Qualifications, Experience and Special Responsibilities:

Douglas G. Battersby *Non-Executive Chairman* Appointed 18th March 2013	Doug is a petroleum geologist with over fifty years' technical and managerial experience in the Australian and international oil and gas industry. Doug co-founded two ASX listed companies (Eastern Star Gas Limited, which was taken over by Santos Limited in November 2011, and SAPEX Limited, which was taken over by Linc Energy Limited in October 2008), and two private oil and gas exploration/development companies, Darcy Energy Limited, which was sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he was Executive Chairman until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 1990 and 1999 Doug was Technical Director at Petsec Energy Limited, an ASX listed operator in the shallow waters of the Gulf of Mexico with production reaching 100 MMcf per day of gas and 9,000 barrels of oil per day in 1997. Doug holds a Master of Science degree in Petroleum Geology and Geochemistry from Melbourne University.
Maynard V. Smith *Executive Director and Chief Executive Officer* Appointed 18th March 2013	Maynard is a geophysicist with approximately fifty years' technical and managerial experience in the oil and gas industry with a particular focus on the Gulf of Mexico. Maynard co-founded Darcy Energy Limited, sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he has been Chief Executive until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Prior to that, Maynard was Chief Operating Officer with Petsec Energy Limited (1989-2000). In the late 1970s and early 1980s Maynard held senior exploration positions with Tenneco Oil Company, based in Bakersfield, California. Maynard holds a Bachelor of Science degree in Geophysics from California State University at San Diego.
Prent H. Kallenberger *Executive Director and Chief Operating Officer* Appointed 18th March 2013	Prent is a geoscientist with over forty years' experience in the oil and gas industry with extensive exploration and development experience in the Gulf of Mexico, having generated prospects which have led to the drilling of over one hundred and twenty five wells in the Gulf of Mexico and California. He was Vice President of Exploration with Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 2000 and 2006, Prent was Vice President of Exploration with Petsec Energy Inc, where he was responsible for a team of seven people and generated projects leading to the drilling of ten successful wells in twelve attempts in the shallow waters of the Gulf of Mexico. These wells produced 32 Bcf and 1.5 MMBbls of oil. Between 1992 and 1998 Prent was Geophysical Manager with Petsec Energy Inc, a wholly owned subsidiary of Petsec Energy Limited. He holds a Bachelor of Science degree in Geology from Boise State University and Master of Science degree in Geophysics from Colorado School of Mines.

Charles J. Sands *Non-Executive Director* Appointed 18th March 2013	Charles was a non-executive director of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Charles was also a director of Darcy Energy Limited. Charles has over forty years of broad based business and management experience in the USA and is President of A. Santini Storage Company of New Jersey Inc, enabling him to advise on the general business operating environment and practices in the USA. Charles is also an owner of CAT5 Resources a disaster recovery and maintenance company focused on the cellular telephone industry in the US. He holds a Bachelor of Science degree from Monmouth University. Charles is currently a member of the Audit and Risk Management Committee.
Paul A. Young *Non-Executive Director* Appointed 18th March 2013	Paul has been in merchant banking for more than forty five years'. He has extensive experience in the provision of corporate advice to a wide range of Australian and international listed and unlisted companies including restructurings, capital raisings, initial public offerings and mergers and acquisitions. Paul is currently a director of The Australian Wealth Advisors Group Limited, an ASX listed company (ASX: WAG). Paul is an Honours Graduate in Economics (University of Cambridge) and has an Advanced Diploma in Corporate Finance. He is a Fellow of the Institute of Chartered Accountants in England and Wales. Paul is currently Chairman of the Audit and Risk Management Committee.
William R. Sack *Executive Director* Appointed 3rd October 2014	Bill is an explorationist with more than thirty five years' experience in the Gulf of Mexico region in technical, commercial and executive roles. He was appointed to the Board of Directors on 3rd October 2014. Bill's qualifications comprise BSc. Earth Sci./Physics, MSc. Geology and an MBA. He co-founded and served as Managing Partner of Aurora Exploration, LLC, a private entity focused on generating and drilling Gulf of Mexico exploration opportunities that has drilled more than eighty wells with a success rate in excess of 80%, and under his leadership has created substantial growth and monetised investments via multiple corporate level asset sales. Prior to 2000 he served in a variety of exploration and executive roles for Petsec Energy and Shell Offshore. Bill holds a Bachelor of Science degree in Earth Science/Physics from St. Cloud State University, a Master of Science degree in Geology from Michigan State University and a Master of Business Administration from Tulane University.

Company Secretary

Nick Filipovic

Appointed 18th March 2013.

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

Principal Activities

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

Consolidated Results

The loss for the Consolidated Entity after income tax was US$25,885,618 (2025: US$46,788,241 loss).

Directors' Report continued

Summary of Shares and Options on Issue

At 30 June 2026, the Company had 102,843,925 ordinary shares on issue.

During the year ended 30 June 2026, no share options were issued and there were no share options outstanding during the financial year.

No ordinary shares, nor share options were issued subsequent to 30 June 2026 through to the date of this report.

Issuing Entity	Number of Shares	Class of Shares
Byron Energy Limited	102,843,925	Ordinary

Shareholdings and Option Holdings of Directors and Other Key Management Personnel

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

Director/Key Management Personnel	Ordinary Shares	Options Over Ordinary Shares	Exercise Price	Option Expiry Date
D. G. Battersby	5,780,056	0	N/A	N/A
M. V. Smith	3,814,799	0	N/A	N/A
P. H. Kallenberger	288,276	0	N/A	N/A
C. J. Sands	2,496,855	0	N/A	N/A
P. A. Young	3,222,439	0	N/A	N/A
W. R. Sack	439,999	0	N/A	N/A
N. Filipovic	112,135	0	N/A	N/A

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

Review of Operations

Financial Summary

The Group recorded a net loss after income tax of US$25,885,618 for the year ended 30 June 2026, compared to a net loss after tax of US$46,788,241 for the year ended 30 June 2025.

Earnings before interest, tax, amortisation, impairment, realised oil hedge price gains/losses and depreciation and exploration expense ("EBITDAX") for the year ended 30 June 2026 totalled US$14,133,478, a decrease of 5% compared to US$14,937,523 for the year ended 30 June 2025, primarily as a result of lower gas production and lower realised oil prices, partly offset by higher oil production.

EBITDAX* (US$)	Year Ended 30 June 2026	Year Ended 30 June 2025
Loss for the year from continuing operations	**(25,885,618)**	**(46,788,241)**
Net Financial Expenses	**952,697**	3,198,738
Depreciation and amortisation	**8,849,558**	12,312,357
Impairment of Oil and Gas properties	**30,193,351**	44,469,000
Impairment of Exploration and Evaluation assets	**–**	1,863,034
Realised (gain)/loss on forward commodity price contracts	**23,490**	(117,365)
EBITDAX	**14,133,478**	**14,937,523**

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

Corporate and Administration/Other Costs

Corporate and administration costs were US$3,235,196 for the year ended 30 June 2026, compared to US$3,485,214 for the year ended 30 June 2025, mainly due to reduction in staff. Other Expenses were US$1,940,480 for the year ended 30 June 2026, compared to US$1,726,715 for the year ended 30 June 2025 due to costs associated with the recapitalisation process commencing in the September quarter 2025 and still ongoing as of the date of this report.

Impairment Charges

Impairment charges for the year ended 30 June 2026 were US$30,193,351 in respect to oil and gas properties (US$46,332,034 for the year ended 30 June 2025 including exploration asset impairments).

Finance Costs

Finance costs of US$982,218 for the year ended 30 June 2026 were lower than finance costs of US$3,249,769 in 2025, due to the full repayment of the Prepaid Oil Revenue facility in August 2025.

Production, Prices and Revenue

Net production (sales) for the year ended 30 June 2026 was 392,951 barrels of oil and 306,695 mmbtu of gas compared to 376,973 barrels of oil and 847,573 mmbtu of gas for the year ended 30 June 2025. Higher oil production was primarily due to increased production from the SM71 F Platform and SM 58 G Platform. The decrease in gas production was mainly due to lower production from the SM58 G Platform.

For the year ended 30 June 2026, Byron realised an average crude oil sales price (including hedges) of US$67.49 per barrel (after transportation and quality adjustments) and an average realised gas price of US$3.22 (after transportation and quality adjustments), a decrease of approximately 2% for oil prices, with gas remaining relatively flat when compared to the year ended 30 June 2025 where average prices of US$69.03 per barrel of oil and US$3.23 per mmbtu were realised.

Net revenue (after royalties) for the year ended 30 June 2026 of US$27,617,815 was approximately 5% below the US$29,050,394 of net revenue for the year ended 30 June 2025. The decrease in the 2026 year was primarily a result of lower gas production and lower realised oil and gas prices, partly offset by higher oil production.

Byron's share of oil and gas production and sales by field for the 30 June 2026 year, compared to the corresponding period in 2025 is summarised in the table below.

Production (Sales)	Year Ended 30 June 2026	Year Ended 30 June 2025
Net production Byron share (NRI basis) SM71		
Oil (bbls)	**112,833**	107,729
Gas (mmbtu)	**36,249**	166,727
Net production Byron share (NRI basis) SM58		
Oil (bbls)	**269,381**	262,507
Gas (mmbtu)	**270,120**	680,187
Net production Byron share (NRI basis) SM58 E1 well		
Oil (bbls)	**10,737**	6,737
Gas (mmbtu)	**326**	659
Total Net production (NRI basis)		
Oil (bbls)	**392,951**	**376,973**
Gas (mmbtu)	**306,695**	**847,573**

Cost of Sales

Cost of sales, which includes base lease operating expenses, insurance premiums, amortisation and depreciation and gas transportation charges, were US$17,498,965 for the year ended 30 June 2026 compared to US$21,416,950 for the comparable period in 2025. The decrease is primarily due to lower amortisation charges reflecting a lower cost base following last year's financial impairment of oil and gas properties, lower gas production, lower gas transportation charges (lower gas volumes) and lower lease operating costs.

Balance Sheet, Cash Flow and Liquidity

At 30 June 2026, the Consolidated Entity had total assets of US$83,569,234 (30 June 2025: US$119,129,971) and total liabilities of US$18,128,471 (30 June 2025: US$27,684,399) resulting in net assets of US$65,440,763 (30 June 2025: US$91,445,572). The decrease in net assets was primarily due to impairment charges to the Oil and Gas Properties, lower trade and other payables, and lower borrowings.

At 30 June 2026, the Consolidated Entity held cash and cash equivalents of US$4,211,854 (30 June 2025 US$1,599,837).

Borrowings at 30 June 2026 were US$5,346,864 comprising loans from directors and one longstanding shareholder plus financing of the Group's insurance premiums.

Borrowings (US$)	30 June 2026	30 June 2025
Directors and shareholder (Directors' Loans)	**3,088,865**	3,666,903
Insurance premium financing	**2,257,999**	2,381,127
Prepaid oil revenue facility	**–**	2,111,111
Total	**5,346,864**	8,159,141

During the year ended 30 June 2026 overall borrowings decreased from US$8,159,141 to US$5,346,864 due to final principal repayments under the Oil Revenue Prepayment Facility made in August 2025.

In line with Directors' Loan agreements, repayments of principal and interest commenced in April 2026 with final repayments due in March 2027. For additional details refer to Notes to The Financial Statements (refer to Note 24).

Hedging

As at 30 June 2026 the Group had the following hedges in place for future oil production, under a master crude oil sales agreement with the Group's longstanding buyer of its crude oil production.

Period	Daily Hedged WI Volume (bopd)	Period Hedged WI Volume (bbl)	Daily Hedged NRI Volume (bopd)	Period Hedged NRI Volume (bbl)**	NYMEX WTI Fixed Base Price Crude Oil*
(Near) Costless Collars – July 2026 to September 2026	200	18,400	163	14,996	US$60.00 floor to US$66.60 ceiling
(Near) Costless Collars – October 2026 to December 2026	200	18,400	163	14,996	US$60.00 floor to US$65 ceiling

* West Texas Intermediate (WTI) fixed base price is then adjusted for NYMEX Roll, LLS/WTI price differentials, Transportation (estimated at -US$6.2387/barrel +-0.20) to arrive at a realised price; the fixed price per barrel under the FSA qualifies for purposes of royalty calculations.

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

Operations Update

South Marsh Island 71

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

Water depth in the area is approximately 137 feet.

Oil and gas production from the Byron operated SM71 F platform began on 23 March 2018 from three wells, F1, F2 and F3. Production from the F4 well commenced in mid-March 2020. The F1 and F3 wells are producing in the primary D5 Sand reservoir, the F2 and F4 wells are both producing intermittently from the J1 sand.

Total net sales volumes for all wells on the SM71 F Platform for the year ended 30 June 2026 and June 2025 year is shown in the table below.

Production/Sales SM71 F Platform (Net to Byron)*	Year Ended 30 June 2026 (12 Months)	Year Ended 30 June 2025 (12 Months)
Oil (bbls)	**112,833**	107,729
Gas (mmbtu)	**36,249**	166,727

* Byron's share of contribution form SM71 wells comprising F1, F2, F3, F4 and F5.

Higher oil production from SM71 F Platform for the 2026 year was mainly due to lower down time, with increased production from the SM71 F4 well partly offset by lower production, as expected from the SM71 F1 well, the main producing well on the platform. The SM71 F1 well continues to produce water-free with the rate managed to optimise the D5 Sand reservoir's oil production.

South Marsh Island 58

Byron holds all the operator's rights, title, and interest in and to the South Marsh Island block 58 ("SM58") lease to a depth of 13,639 feet subsea with 100% WI and 83.33% NRI. Below 13,639 feet subsea, Byron has a 50% WI (41.67% NRI) under a pre-existing exploration agreement. To date, all identified drilling opportunities on the SM58 lease are above 13,639 feet subsea. Byron also holds an interest in the SM69 E2 well with a 70% WI and a 58.33% NRI.

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

Total net sales volumes for all wells on the SM58 G Platform for the years ended 30 June 2026 and June 2025 is shown in the table below.

Production/Sales SM58 G Platform (Net to Byron)*	Year Ended 30 June 2026 (12 Months)	Year Ended 30 June 2025 (12 Months)
Oil (bbls)	**269,381**	262,507
Gas (mmbtu)	**270,120**	680,187

* Byron's share of contribution form SM58 wells comprising G1, G2, G3, G4, G5, G6 and E2 wells.

Higher oil production from SM58 G Platform for the 2026 year was largely due to change of zones in the SM58 G6 BP1 well, from the N2 Sand to the more productive L2 Sand originally the primary target of the G6 BP1 well partly offset by expected lower production from the E2 well. Lower gas production was mainly due to lower production from the SM58G-1BP1 (Upper O) and the SM58 G6 BP1 well.

South Marsh Island 58 E1 Well Bore and SM69 E Platform

Byron holds a non-operated 53% WI (44.167% NRI) in the South Marsh Island 69 E platform with one active producing well, the SM58 E1 well.

For the year ended 30 June 2026, Byron's share of net production was 10,737 barrels of oil and 326 mmbtu, compared to 6,737 barrels of oil and 659 mmbtu in the previous year.

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

Reserves and Resources

Byron's independently assessed reserves and resources as of 30 June 2026, compared to 2025, are shown in the table below:

Reserves (Net to Byron mboe)	Category	30 June 2026	30 June 2025
Proved Producing	PDP	**1,660**	1,780
Proved Behind Pipe	PDBP	**1,414**	1,418
Proved Undeveloped	PUD	**6,100**	4,992
Proved	**1P**	**9,174**	**8,190**
Probable		**4,454**	4,530
Proved and Probable	**2P**	**13,628**	**12,720**
Possible		**5,779**	5,889
Proved, Probable and Possible	**3P**	**19,407**	**18,609**
Prospective Resources	**Pr**	**33,098**	**30,706**

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

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

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

The Company's 1P remaining reserves of 9.2 Mmboe as of 30 June 2026 increased by approximately 12% year on year, mainly due to mapping of additional proved undeveloped reserves at SM58 partly offset by production for the year ended 30 June 2026.

Remaining 2P reserves of 13.6 Mmboe and 3P reserves of 19.4 Mmboe, as of 30 June 2026, increased by approximately 7% and 4% respectively.

The Company's Prospective Resources as of 30 June 2026 increased by approximately 8% year on year to 33.1 Mmboe largely due to inclusion of the SM57 lease during the year.

Portfolio Optimisation

During the 2026 financial year, Byron reviewed its portfolio of exploration and evaluation leases and began to relinquish those leases ranked lower on technical and economic risk criteria as they came up for renewal thus saving outlays on advance rentals and geological and geophysical studies. Consequently, the SM61 lease was relinquished.

Byron was the high bidder on South Marsh Island Block 57 at OCS Lease Sale Big Beautiful Gulf 1 (BBG1) held in New Orleans on 10 December 2025. Byron's bid amount was US$143,948 (US$26.50 per acre) for the SM57 lease. A high bid is subject to a review of bid adequacy by the Bureau of Ocean Energy Management (BOEM) and may be rejected if deemed inadequate. In January 2026, Byron was formally awarded the SM57 lease. Byron previously relinquished the SM57 lease in April 2025. By relinquishing and re-bidding Byron saved one annual advance rental and extended the lease term by nearly 4 years with the Net Revenue Interest increasing from 81.25% to 87.5% under the new lease.

Oil and Gas Leases

As at 30 June 2026, 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 57	Byron	100.00/87.50	January 2031	21.98
Block 70	Byron	100.00/81.25	March 2029	22.13
Block 58 (excluding E1 well)	Byron	100.00/83.33**		
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	Production	20.23
SM69 (NE ¼ of NE ¼) (E-2 well)	Byron	70.00/58.33	Production	1.30

* 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 Group

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 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 Group in executing its strategy and delivering on its targets are described below.

Risks Relating to the Group's industry, Business and Financial Condition

There are a number of risks which may impact on the operating and financial performance of the Group and therefore, on the value of its shares. Some of these risks can be mitigated by the Group's systems and internal controls, but many are outside of the control of the Group and the Board. There can be no guarantee that the Group 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 Group and the oil and gas industry could materially impact the Group'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 Group faces, and other factors currently considered immaterial or unknown may impact future operations.

Inflationary Risk

Cost inflation, including significant increases in raw materials costs, labour rates, and domestic transportation costs have and could continue to impact profitability. Such cost increases did not materially impact the Group's 2026 operating results and financial condition or results, there is no guarantee that the Group can reduce costs to fully mitigate the effect of inflation on its cost base and business, which may adversely impact future sales margins and profitability.

Oil and Natural Gas Price Risk

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

Financing Risk

Byron's business plan, which includes participation in seismic data purchases, lease acquisitions and the drilling of exploration and development prospects, has required and is expected to continue to require capital expenditures. Byron may require additional financing to fund its planned growth. This additional financing may be in the form of equity, debt or a combination thereof. Byron may also obtain capital by farming out part of its working interest in one or more of its oil and gas properties. Byron's ability to raise additional capital will depend on the results of its operations and the status of various capital and industry markets at the time it seeks such capital. Accordingly, additional financing may not be available on acceptable terms, if at all. In the event additional capital resources are unavailable, Byron may be required to curtail its exploration and development activities. It is difficult to quantify the amount of financing Byron may need to fund its planned growth in the longer term. The amount of funding Byron may need in the future depends on various factors, including but not limited to; (i) the Group's financial condition, and (ii) the success or otherwise of its exploration and development programme. Further, the availability of such funding may depend on various factors, including but not limited to, the liquidity of the Company's shares at the time the Company seeks to raise funds and the prevailing and forecast market price of oil and natural gas. If the Company 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 Group'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 Group. 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 Group'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 Group's reserve report have produced for a relatively short period of time. Accordingly, some of the Group'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 Group'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, Byron's proved reserves are proved developed producing, behind pipe or undeveloped. Accordingly, Byron's opportunities to increase production from its existing proved reserves are largely reliant on developing undeveloped 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 Group's business, financial condition or results of operations.

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

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

Operating Risk

The oil and natural gas business, including production activities, involves a variety of operating risks, including blowouts, fires and explosions; surface cratering; uncontrollable flows of underground natural gas, oil or formation water; natural disasters; pipe and cement failures; casing collapses; stuck drilling and service tools; reservoir compaction; abnormal pressure formation; environmental hazards such as natural gas leaks, oil spills, pipeline and tank ruptures or unauthorised discharges of brine, toxic gases or well fluids; capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which Byron has no control; repeated shut-ins of Byron's well bores could significantly damage the Group'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 Group 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 Group 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 Group's financial position and results of operations.

Execution Risk (Drilling and Operating Programmes)

Shortages or increases in the cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect Byron's operations which could have a material adverse effect on its business, financial condition and results. Where Byron is the operator it assumes additional responsibilities and risks. As the designated operator, Byron, under the BOEM regulations, will be required to post bonds for exploration and development activities as well as for production activities and future decommissioning obligations. There is the risk that the Group may not be able to obtain sufficient bonding and may have to collateralise obligations with cash. If the Group 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 Byron 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 Group'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

The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States and in foreign countries. Numerous proposals have been made at the international, national, regional and state levels of government to monitor and limit existing emissions of Green House Gases (GHG) as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the Environmental Protection Authority (EPA) has adopted regulations under the existing Clean Air Act (CAA) that, among other things, impose pre-construction and operating permit requirements on certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources and implement New Source Performance Standards directing the reduction of methane from certain new, modified or reconstructed facilities in the oil and natural gas sector.

In recent years there has been increased regulation of methane emissions from the oil and gas sector. For example, in December 2023, the EPA published a final rule establishing more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Fines and penalties for violations of these rules can be substantial. The final methane rule is currently being challenged by 23 states and a coalition of industry groups in the U.S. Circuit Court of Appeals for the D.C. Circuit. In February 2025, the court granted the EPA's motion to hold the consolidated cases in abeyance while the EPA reviews the final rule. While the Trump Administration may take action to revise, repeal, or otherwise modify the final methane rule, the substance or timing of such action, if any, is uncertain. Although these federal methane rules only apply to onshore and state water oil and gas operations, more stringent regulation of methane or greenhouse gases from the oil and gas sector has the potential to increase Byron's compliance costs and could adversely impact its operations.

At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement among participating nations to limit their GHG emissions through individually determined emissions reduction goals every five years after 2020. However, on January 20, 2025, President Trump issued an Executive Order re-withdrawing the United States from the Paris Agreement and from any other commitments made under the United Nations Framework Convention on Climate Change. Additionally, President Trump revoked any purported financial commitment made by the United States pursuant to the same. The full impact of these actions is uncertain at this time.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risk regarding climate change. In the United States, President Biden issued several executive orders calling for more expansive action to address climate change and limit new oil and gas operations on federal lands and waters, though many of these initiatives have been subsequently revoked by President Trump. Other actions that were pursued by the Biden Administration, and may be pursued in future administrations, include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquified natural gas (LNG) 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 a 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. Byron is not currently a defendant in any of these lawsuits but 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.

Additionally, Byron's access to capital may be impacted by climate change policies. Certain shareholders and bondholders currently invested in fossil fuel energy companies such as Byron, but 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. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. A material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development and production activities, which could impact Byron's business and operations.

Finally, some scientists have concluded that increasing concentrations of GHG emissions 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 extreme climatic events, as well as chronic shifts in temperature and precipitation patterns. Byron's offshore operations are particularly at risk from severe climatic events, which have the potential to cause physical damage to our assets and thus could have an adverse effect on our exploration and production operations. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products Byron produces. While consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, Byron's ability to mitigate the adverse impacts of these events depends in part on the effectiveness of the Group's facilities and disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Although the Trump Administration has signalled a rollback of the climate regulatory environment, continuing political and social attention to the issue of climate change has resulted in both existing and proposed international agreements and national, regional, and local legislation and regulatory measures to limit GHG emissions and mitigate the effects of climate change. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Compliance with these rules or others could result in increased compliance costs on Byron's operations.

Separately, the SEC finalized a rule in March 2024 that establishes a framework for the reporting of climate risks, targets and metrics. The rule was stayed pending litigation and on February 11, 2025, SEC Acting Chairman Mark T. Uyeda requested that the U.S. Court of Appeals for the Eighth Circuit not schedule argument in the case while the SEC reconsiders the March 2024 rule. Subsequently, in March 2025 the SEC announced that it has voted to end the legal defence of its climate disclosure rules, effectively walking away from its regulation requiring companies to report on climate risks and greenhouse gas emissions, without actually having to rescind the rules.

Australia's climate-related financial disclosure (CRFD) regime commenced on 1 January 2025 after the Treasury Laws Amendment (Financial Market Infrastructure and Other Measures) Bill 2024 (Cth) (the Act) received royal assent on 17 September 2024. While jurisdictions such as the European Union and Japan have focused on listed entities only, the Act provides for both listed and unlisted entities to trigger reporting, with larger entities being required to commence reporting earlier. The Australian Accounting Standards Board (AASB) has released ASRS S2, a standard that will be regulated by the Australian Securities and Investments Commission (ASIC). This standard mandates climate-related disclosures for eligible companies.

Byron does not currently have to comply with ASRS S2 because it does not fall within any of the three specified categories.

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 Group's business are the following: Waste Discharges, Air Emissions and Climate Change, Oil Pollution Act, National Environmental Policy Act, Worker Safety, Safe Drinking Water Act, Offshore Drilling, Hazardous Substances and Wastes and Protected and Endangered Species.

Oil and Gas Transport and Processing Risk

All of Byron's oil and natural gas is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or Byron's transportation capacity is materially restricted or is unavailable in the future, the Group'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 the Company 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 Group'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 Group'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 Group'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 Group does not currently have in place any foreign exchange hedging arrangements. However, foreign exchange hedging strategies will be reviewed by the Group from time to time, implementation of any strategy will depend, inter alia, upon the foreign exchange hedging options available to the Group from time to time, the cash cost of entering into hedging transactions and the Group's capacity to pay for such costs.

Key Management Risk

To a large extent, the Group 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 Group's operations. Byron does not maintain or plan to obtain for the benefit of the Group any insurance against the loss of any of these individuals.

Regulatory Risk

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

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

U.S. federal offshore oil and gas leasing and permitting practices have been subject to numerous challenges, delays, and moratoriums which has curtailed the Group's ability to seek additional new federal leases and may continue to delay or prevent bidding and obtaining new federal leases. Additionally, in response to a November 2021 report from the Department of Interior (DOI) on federal oil and gas leasing and permitting practices, the Inflation Reduction Act of 2022 (the "IRA 2022") increased onshore royalty rates to 16.7% and offshore royalty rates to no less than 16.7% but not more than 18.8% for the next ten years.. However, the Trump Administration has taken action to revoke or rescind certain actions by the previous administration that placed limitations on offshore oil and gas leasing and permitting. For example, President Trump issued Executive Orders lifting restrictions on oil and gas leasing off the coast of Alaska and encouraging further OCS oil and gas exploration and production.

The Biden administration was operating under the 2024-2029 Five-Year Leasing Program which began on July 1, 2024, and was to continue through June 30, 2029, and included a maximum of three potential oil and gas lease sales in the U.S. Gulf of Mexico scheduled to be held in years 2025, 2027 and 2029. Despite legal challenges, on April 1, 2024, BOEM announced the availability of the Area Identification for proposed U.S. Gulf of America lease sales 262, 263 and 264 pursuant to the 2024-2029 Five-Year Leasing Program. In October 2025, the Trump Administration enacted the "One Big Beautiful Bill Act" (the "OBBBA"), signalling a decisive shift back toward traditional fossil fuel development.

While the Inflation Reduction Act of 2022 ("IRA") ushered in a new era for clean energy, the OBBBA walks back some of the IRA provisions and clears the way for renewed oil and gas production on federal lands and waters.

The OBBBA increased the royalty rate applicable to onshore oil and gas leases on federal lands introduced by the IRA. In 2022, the IRA significantly raised federal royalty rates for those leases from 12.5% to 16.67%,. The Act restores the royalty rates to their pre-IRA levels, making drilling on federal land and offshore areas more financially attractive. The OBBBA also makes favourable changes to the treatment of intangible drilling costs, which are the upfront expenses associated with developing wells, for taxpayers subject to the corporate alternative minimum tax.

The OBBBA also mandates new lease sales across federal lands and waters. Under the prior administration, federal lease sales for oil and gas development had slowed considerably. The Department of the Interior is now required to hold at least 30 offshore lease sales for the ocean basin on the Gulf Coast of America, including one by the end of 2025, the OCS Lease Sale Big Beautiful Gulf 1 (BBG1) was held in New Orleans on 10 December 2025, followed by two per year thereafter.

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

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

Seismic Risk

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

Lease Termination Risk

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

Working Interest Partners' Risk

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

Profitability and Impairment Write-downs Risk

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

Bonding Risk

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

Cyber Security Risk

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, companies depend on digital technologies to interpret seismic data, conduct reservoir modelling and record financial and other data. The Group 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 Group'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 Group'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 Group'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 Group 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.

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.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities in the OCS. In April 2024, BOEM ruled that the OCS oil and natural gas lessees and grant holders are required to provide supplemental financial assurance to backstop their decommissioning obligations. In March 2026 BOEM published a proposed rule setting forth amendments to relax the existing financial assurance regulatory framework. The proposed rule is subject to a public comment period, which is expected to end in mid-2026. While this can be viewed as a positive development, the substance and timing of future legal and regulatory actions cannot be predicted at this time. Additionally, regardless of any changes that may come as a result of the Secretarial Order, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of non-performance of the interest holder's decommissioning liabilities.

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.

Level of Indebtedness Risk

Byron utilises debt to fund its operations from time to time. The covenants in future loan agreements could negatively impact the Group'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 Group has in the past and may in the future enter into hedging arrangements for a portion of oil and natural gas production, including, forward sale agreements and derivatives such as puts, collars and fixed-price swaps. Changes in the fair value of derivative instruments are recognized in earnings. Accordingly, earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose the Group 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 Group could receive from increases in the prices for oil and natural gas and may expose the Group to cash margin requirements in certain cases.

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 Group's current ESG governance structure may not allow it to adequately identify or manage ESG related risks and opportunities, which may include failing to achieve ESG-related strategies and goals.

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

Key Risks in Investing in Unlisted Shares

The Company was removed from the Official List of the ASX on 17 July 2024 under Listing Rule 17.11, at the request of the Company, after shareholders resolved to delist the Company. Byron formerly traded under the ticker ASX: BYE. Key risks in investing in unlisted shares are:

- Limited or no liquidity – shareholders will no longer have the ability to sell their shares and realise their investment in the Company via trading on the ASX. Following delisting, the Company's shares will only be capable of sale via off-market private transactions which will require shareholders to identify and agree terms with potential purchasers in accordance with the *Corporations Act 2001* (Cth) (Corporations Act) and the Company's Constitution;
- Reduce disclosure obligations – the Company will no longer be required to comply with the continuous disclosure obligations and periodic disclosure obligations under Chapters 3 and 4 of the ASX Listing Rules; however, the Company will remain subject to continuous disclosure and periodic disclosure obligations under the *Corporations Act 2001*; in addition to the reduction in the Company's continuous and periodic disclosure obligations, the Company will no longer be subject to the application of other ASX Listing Rules which are intended to protect, or provide information to, shareholders (such as Chapters 7, 10, 11 and 14 of the Corporations Act; and
- Reduced access to capital – while the Board believes the Company will have better access to potential capital and on more favourable terms than would otherwise be available if the Company was to remain listed on the ASX, there is no certainty that the Company will in fact obtain better access to capital and/or on more favourable terms post-delisting.

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.

Significant Events After the Balance Date

There has been no matter or circumstance since 30 June 2026 which has significantly affected or may significantly affect the operations of the Consolidated Entity, the results of those operations or the state of affairs of the Consolidated Entity in subsequent financial years other than those described below:

- on 1 September 2026, Byron published its annual 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.

As the Company is an 'unlisted disclosing entity' for the purposes of the *Corporations Act 2001* and subject to the continuous disclosure obligations set out in Chapter 6CA, under which as an unlisted disclosing entity, if the Company (i) becomes aware of information that is not generally available, and (ii) a reasonable person would expect the information, if it were generally available, to have a material effect on the price or value of its securities, the Company must publish continuous disclosure announcements on it's website.

Dividends

No dividends in respect of the current financial year have been paid, declared or recommended for payment (2025: 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.

Auditor Independence Declaration

A copy of the auditor's independence declaration under s.307C of the *Corporations Act 2001* in relation to the audit of the full year is included in this report. The auditor's independence declaration is included on page 37.

Directors' Report continued

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.

Rounding Off of Amounts

The Company is an entity of the kind referred to in ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2026/183 and in accordance with that Corporations Instrument amounts in the directors' report and the financial statements are rounded off to the nearest dollar, unless otherwise indicated.

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 were three Board meetings and three Audit and Risk Management Committee meetings. 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	3	3	–	–
Maynard V. Smith	3	3	–	–
Prent H. Kallenberger	3	3	–	–
Charles J. Sands	3	3	3	3
Paul A. Young	3	3	3	3
William R. Sack	3	3	–	–

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

On behalf of the directors

D. G. Battersby
Chairman

29 September 2026

Auditor's Independence Declaration

Deloitte.

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29 September 2026

Board of Directors
Byron Energy Limited
Level 5, 530 Collins Street
Melbourne VIC 3000

Dear Board Members

Auditor's Independence Declaration to Byron Energy Limited

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

As lead audit partner for the audit of the financial report of Byron Energy Limited for the financial year ended 30 June 2026, I declare that to the best of my knowledge and belief, there have been no contraventions of:

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

Yours faithfully

DELOITTE TOUCHE TOHMATSU

DELOITTE TOUCHE TOHMATSU

Jane Fisher
Partner
Chartered Accountants

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Member of Deloitte Asia Pacific Limited and the Deloitte organisation.

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the Financial Year Ended 30 June 2026

	Note	Consolidated 2026 US$	Consolidated 2025 US$
Continuing operations			
Oil sales		**32,149,948**	31,858,106
Gas sales		**1,331,057**	3,706,485
Total revenue from sales of oil and gas		**33,481,005**	**35,564,591**
Royalty expense		**(5,863,190)**	(6,514,197)
Cost of sales	2	**(17,498,965)**	(21,416,950)
Gross profit		**10,118,850**	**7,633,444**
Recoupment of operator overheads/product handling fees/gas transportation revenue		**556,077**	604,222
Realised gain (loss) on forward commodity price contracts		**(23,490)**	117,365
Corporate and administration costs		**(3,235,196)**	(3,485,214)
Impairment expense	9(b)	**(30,193,351)**	(46,332,034)
Depreciation of property, plant and equipment		**(215,331)**	(400,571)
Other expenses		**(1,940,480)**	(1,726,715)
Finance income	3	**29,521**	51,031
Finance expense	3	**(982,218)**	(3,249,769)
Loss before tax		**(25,885,618)**	**(46,788,241)**
Income tax expense	4	**–**	–
Loss for the year from continuing operations		**(25,885,618)**	**(46,788,241)**
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Exchange differences on translating the parent entity group	17	**(119,191)**	2,327
Total comprehensive loss for the year		**(26,004,809)**	**(46,785,914)**

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

As at 30 June 2026

	Note	Consolidated 2026 US$	Consolidated 2025 US$
Assets			
Current assets			
Cash and cash equivalents	22(b)	**4,211,854**	1,599,837
Trade and other receivables	7	**3,178,362**	2,879,648
Other	8	**2,860,755**	3,054,795
Total current assets		**10,250,971**	**7,534,280**
Non-current assets			
Exploration and evaluation assets	9(a)	**1,131,873**	891,204
Oil and gas properties	9(b)	**68,992,093**	107,295,100
Right-of-use assets	10	**124,048**	336,700
Property, plant and equipment	12	**15,707**	18,145
Other	8	**3,054,542**	3,054,542
Total non-current assets		**73,318,263**	**111,595,691**
Total assets		**83,569,234**	**119,129,971**
Liabilities			
Current liabilities			
Trade and other payables	13	**2,011,888**	7,142,035
Provisions	14	**208,607**	205,109
Lease liabilities	11	**141,748**	222,558
Borrowings	15	**5,346,864**	4,492,238
Total current liabilities		**7,709,107**	**12,061,940**
Non-current liabilities			
Trade and other payables	13	**325,000**	2,597,952
Provisions	14	**10,094,364**	9,215,856
Lease liabilities	11	**–**	141,748
Borrowings	15	**–**	3,666,903
Total non-current liabilities		**10,419,364**	**15,622,459**
Total liabilities		**18,128,471**	**27,684,399**
Net assets		**65,440,763**	**91,445,572**
Equity			
Issued capital	16	**138,916,729**	138,916,729
Foreign currency translation reserve	17	**(154,229)**	(35,038)
Share option reserve		**8,037,559**	8,037,559
Accumulated losses		**(81,359,296)**	(55,473,678)
Total equity		**65,440,763**	**91,445,572**

The accompanying notes form part of these financial statements.

Consolidated Statement of Changes in Equity

For the Financial Year Ended 30 June 2026

Consolidated Entity	Ordinary Share Capital US$	Share Option Reserve US$	Other Reserves US$	Accumulated Losses US$	Total US$
Balance at 1 July 2024	**138,916,729**	**8,037,559**	**(37,365)**	**(8,685,437)**	**138,231,486**
Loss for the year	–	–	–	(46,788,241)	(46,788,241)
Exchange differences arising on translation of the parent entity group	–	–	2,327	–	2,327
Total comprehensive profit/(loss) for the year	–	–	2,327	(46,788,241)	(46,785,914)
Balance at 30 June 2025	**138,916,729**	**8,037,559**	**(35,038)**	**(55,473,678)**	**91,445,572**
Balance at 1 July 2025	**138,916,729**	**8,037,559**	**(35,038)**	**(55,473,678)**	**91,445,572**
Loss for the year	**–**	**–**	**–**	**(25,885,618)**	**(25,885,618)**
Exchange differences arising on translation of the parent entity group	**–**	**–**	**(119,191)**	**–**	**(119,191)**
Total comprehensive profit/(loss) for the year	**–**	**–**	**(119,191)**	**(25,885,618)**	**(26,004,809)**
Balance at 30 June 2026	**138,916,729**	**8,037,559**	**(154,229)**	**(81,359,296)**	**65,440,763**

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

For the Financial Year Ended 30 June 2026

	Note	Consolidated 2026 US$	Consolidated 2025 US$
Cash flows from operating activities			
Receipts from customers		**33,164,841**	37,534,077
Payments to suppliers and employees		**(19,673,378)**	(20,868,520)
Interest paid		**(1,489,578)**	(1,426,329)
Interest received		**5,393**	12,975
Net cash flows from operating activities	22(a)	**12,007,278**	**15,252,203**
Cash flows from investing activities			
Payments for development of oil and gas properties		**(5,928,619)**	(2,759,232)
Payments for exploration and evaluation assets		**(240,669)**	(357,334)
Net cash flows used in investing activities		**(6,169,288)**	**(3,116,566)**
Cash flows from financing activities			
Repayment of borrowings (director/shareholder repayments)		**(872,680)**	–
Repayment of lease liabilities		**(245,922)**	(468,213)
Repayment of borrowings (prepaid revenue repayments)		**(2,111,111)**	(12,666,667)
Net cash flows used in financing activities		**(3,229,713)**	**(13,134,880)**
Net increase (decrease) in cash and cash equivalents held		**2,608,277**	**(999,243)**
Cash and cash equivalents at the beginning of the year		**1,599,837**	**2,599,590**
Effect of exchange rate changes on the balance of cash held in foreign currencies		**3,740**	(510)
Cash and cash equivalents at the end of the year	22(b)	**4,211,854**	**1,599,837**

The accompanying notes form part of these financial statements.

Notes to the Financial Statements

For the Financial Year Ended 30 June 2026

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1. Summary of Material 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 other authoritative pronouncements issued by the Australian Accounting Standards Board (AASB) 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.

Compliance with Australian Accounting Standards ensures that the financial statements and notes of the Group comply with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB). Consequently, this financial report has been prepared in accordance with and complies with IFRS Accounting Standards as issued by the IASB.

The financial statements were authorised for issue by the directors on 29 September 2026.

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

Presentation Currency and Rounding

These financial statements are presented in United States Dollars ($). Foreign operations are included in accordance with the policies set out in Note 1e.

The company is an entity of a kind referred to in ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2026/183 and in accordance with that Corporations Instrument amounts the financial report are rounded off to the nearest dollar, unless otherwise indicated.

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.

Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amount of assets and liabilities within the next financial year are included in the following notes.

Areas of Judgement and Estimate

Oil and Gas Properties

- Amortisation – Note 9b
- Impairment – Note 9b
- Provision for Restoration – Note 14

Adoption of New and Revised Accounting Standards

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

Standards and Interpretations Issued Not Yet Effective – IASB and IFRIC Interpretations

At the date of authorisation of the financial statements, the following IASB Standards, IFRIC Interpretations and AASB Standards 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 18 Presentation and Disclosure in Financial Statements	1 January 2027	30 June 2028

1. Summary of Material Accounting Policies continued

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. This note provides a list of all other material accounting policies adopted in the preparation of these consolidated financial statements. These policies have been consistently applied to all the periods presented, unless otherwise stated. The financial statements are for the Group consisting of Byron Energy and its subsidiaries.

(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 Assets

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

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

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

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

Farm In and Farm Outs:

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

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

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

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

All other exploration and evaluation costs are expensed as incurred.

(c) Oil and Gas Properties

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

In addition, costs include:

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

Amortisation

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

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

(d) Impairment

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

Calculation of the Recoverable Amount

The recoverable amount of an asset is the greater of its fair value less cost to sell and value in use. In assessing the fair value less cost to sell, the estimated future cash flows are discounted to their present value using a pre-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 9 for further details.

1. Summary of Material Accounting Policies continued

(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) Revenue Recognition

Oil and Gas Revenue

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

(g) Provisions

Site Restoration and Rehabilitation of Oil and Gas Properties

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

(h) Borrowings

Financial Liabilities

Financial liabilities, including borrowings and trade and other payables, are initially measured at fair value, net of transaction costs. 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.

(i) 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.

(j) Reserves

Foreign Currency Translation Reserve

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

Share Option Reserve

The share option reserve arises on the grant of share options to directors, staff, consultants and other service providers to the Group, if the share options vest immediately. Where share options vest over time the share option reserve rise over the vesting period. Amounts are transferred out of the reserve and into issued capital when the options are exercised.

(k) Going Concern

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.

For the year ended 30 June 2026 the Group reported a loss before tax of US$25,885,618 (2025: US$46,788,241 loss), generated net cash inflows from operating activities of US$12,007,278 (2025: US$15,252,203) and net cash outflows from investing and financing activities of US$9,399,001 (2025: US$16,251,446). As at 30 June 2026 the Group reported a working capital surplus of US$2,541,864 (30 June 2025: deficiency of US$4,527,660).

The net current asset position and improvement from the previous period is principally driven by:

(i) Higher cash and cash equivalents balance; and

(ii) Lower trade and other payables.

The directors have reviewed the business outlook, cash flow forecasts and immediate capital requirements and are satisfied that it's appropriate to prepare the financial report on the going concern basis.

2. Loss for the Year

	Consolidated	
	2026 US$	**2025 US$**
Loss for the year has been arrived at after charging the following items of expense		
Cost of sales		
Lease operating costs	**8,754,175**	9,173,590
Gas transportation costs	**110,563**	331,574
Amortisation of oil and gas properties	**8,634,227**	11,911,786
	17,498,965	21,416,950
Professional and consulting costs	**1,356,797**	1,018,843
Insurance	**178,049**	189,866
Office lease rental expense including outgoings (short term leases)	**167,664**	143,201
Employee benefits expense		
Salaries and wages	**2,507,727**	2,740,688
Defined contribution superannuation expense	**52,732**	48,278
	2,560,459	2,788,966

3. Financial Income and Expenses

Financial Income		
Interest income	**29,521**	51,031
	29,521	51,031
Financial Expense		
Interest expense nonrelated parties	**92,499**	2,539,685
Lease finance costs	**23,364**	53,018
Unwinding of discount on rehabilitation of oil and gas properties	**404,221**	241,195
Interest expense paid or accrued on loans from related parties	**462,134**	415,871
	982,218	3,249,769

4. Income Tax

	Consolidated	
	2026 US$	**2025 US$**
Income tax recognised in profit and loss	**–**	–
The income tax expense for the year can be reconciled to the accounting profit as follows:		
Loss before tax from continuing operations	**(25,885,618)**	(46,788,241)
Income tax (benefit)/expense calculated at 30.0% (30.0% 2025)	**(7,765,685)**	(14,036,472)
Effect of expenses that are not deductible in determining taxable profit	**988**	60,847
Effect of different tax rates of subsidiaries operating in other jurisdictions	**247,251**	452,892
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	**7,517,446**	13,522,733
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	**6,439,799**	5,850,792
USA tax losses	**31,921,470**	35,084,065
Temporary differences	**(6,669,424)**	(17,044,581)
Total deferred tax assets not recognised	**31,691,845**	23,890,276

The potential deferred tax asset will only be recognised if:

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

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

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

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

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

5. 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$73,313,261 (2025: US$111,590,681) and Australia US$5,002 (2025: US$5,010).

6. 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:

	2026	2025
Spot rate at 30 June	**0.6869**	0.6550
Average rate for year	**0.6785**	0.6482

7. Trade and Other Receivables

	Consolidated	
	2026 US$	2025 US$
Current		
Oil and gas sales receivables	**2,889,561**	2,635,441
Joint operating arrangements receivables	**126,795**	107,773
Interest receivable	**133,291**	109,164
GST receivable/other receivables	**28,715**	27,270
	3,178,362	2,879,648

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

8. Other Assets

Current		
Prepayments	**2,854,663**	3,025,594
Oil price hedge receivable	**–**	23,490
Security deposits	**6,092**	5,711
	2,860,755	3,054,795
Non-current		
Security deposits	**3,054,542**	3,054,542

9 (a). Exploration and Evaluation Assets

	Consolidated	
	2026 US$	**2025 US$**
Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**1,133,873**	891,204
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**891,204**	2,546,394
Additions at cost	**242,669**	207,844
Impairment expense	**–**	(1,863,034)
Carrying amount at the end of the financial year	**1,133,873**	891,204

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.

Impairment charges for the year ended 30 June 2026 were US$ Nil. For the year ended 30 June 2025, impairment charges were US$1,863,034 representing the relinquishments of the Grand Isle 63/72, SM57, SM60 and SM66 leases during the financial year and write down to zero of the SM61 lease carrying value which was relinquishment prior to its annual anniversary.

9 (b). Oil and Gas Properties

Costs carried forward in respect of areas in the oil and gas properties:	**68,992,093**	107,295,100
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**107,295,100**	151,811,973
Additions at cost	**51,270**	8,478,977
Additions for site restoration	**473,301**	3,384,936
Impairment expense	**(30,193,351)**	(44,469,000)
Amortisation of oil and gas properties included in cost of sales	**(8,634,227)**	(11,911,786)
Carrying amount at the end of the financial year	**68,992,093**	107,295,100

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

SM71 F	**25,334,674**	27,959,449
SM58 G	**42,127,183**	77,680,368
SM69 E	**1,530,236**	1,655,283
Carrying amount at the end of the financial year	**68,992,093**	107,295,100

9 (b). Oil and Gas Properties continued

Recoverable Amount

At year end, the Company's oil and gas properties were assessed for impairment indicators in accordance with AASB 136. Indicators of impairment were present. Several factors have contributed to the presence of indicators of impairment for the Company's CGU's, including declining production, lower realised and forecast oil prices.

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 pre-tax discount rate of 16.0%, reflective of 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 developed proved and probable reserves (2P reserves) over the economic life of each field of approximately 20 years, although most of the 2P production is estimated to be produced within the next ten years, (ii) hydrocarbon prices that the Consolidated Entity estimates to be reasonable, taking into account historical prices, current prices and prices used in making its exploration and development decisions, and (iii) future operating and development costs as estimated by the Company and reviewed for reasonableness by the independent petroleum engineers.

The estimated recoverable amount of Byron's oil and gas properties relies on achieving management's forecasts of various assumptions and is sensitive to a change in estimated recoverable reserves and production therefrom, and oil prices. A 10% reduction in oil production or a 10% reduction in oil prices would reduce the estimated recoverable values by approximately 9% for SM71 F, 11% for SM58 G and 11% for SM69 E. The estimated recoverable amount is less sensitive to discount rates, operating expenses and capital expenditure estimates. Changes in the aforementioned factors may result in additional impairment indicators for the Company's assets and CGU's in the future. In the event the recoverable amount of assets is impacted by changes in these, the carrying amount of the asset may be further impaired.

10. Right-of-use Assets

	Consolidated	
	2026 US$	**2025 US$**
Office Lease		
Opening balance	**336,700**	549,352
New lease additions for financial year	**–**	–
Charge for the year	**(212,652)**	(212,652)
Carrying amount at the end of the financial period	**124,048**	336,700
Total right-of-use assets	**124,048**	336,700
Amounts recognised in profit and loss		
Depreciation expense on right-of-use assets	**212,652**	396,161
Interest expense on lease liabilities	**23,364**	53,018
Expense relating to short-term leases including outgoings	**167,664**	143,201

11. Lease Liabilities

	Consolidated	
	2026 US$	**2025 US$**
Not later than one year	**145,148**	245,922
Later than one year and not later than 5 years	**–**	145,148
Minimum lease payments	**145,148**	391,070
Less: Future finance charges	**(3,400)**	(26,764)
Provided for in the financial statements	**141,748**	364,306
Representing lease liabilities:		
Current	**141,748**	222,558
Non-current	**–**	141,748
	141,748	364,306

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.

12. Property, Plant and Equipment

Buildings at cost	**10,034**	9,568
Accumulated depreciation	**(5,032)**	(4,558)
	5,002	5,010
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**5,010**	5,308
Charge for the year	**(248)**	(237)
Foreign currency translation movements	**240**	(61)
Carrying amount at the end of the financial year	**5,002**	5,010
Plant and equipment at cost	**129,949**	129,839
Accumulated depreciation	**(119,244)**	(116,704)
	10,705	13,135
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**13,135**	17,308
Charge for the year	**(2,430)**	(4,173)
Carrying amount at the end of the financial year	**10,705**	13,135
Total property, plant and equipment	**15,707**	18,145

13. Trade and Other Payables

	Consolidated	
	2026 US$	2025 US$
Current		
Trade payables	**1,176,769**	5,218,977
Oil and gas royalties payable	**490,381**	673,523
Joint venture payable	**133,834**	224,725
Accrued interest on prepaid oil revenues/director loans	**169,166**	1,007,263
Other payables	**41,738**	17,547
	2,011,888	7,142,035
Non-current		
Trade payables	**325,000**	2,276,828
Accrued interest on prepaid oil revenues	**–**	310,912
Other payables	**–**	10,212
	325,000	2,597,952

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

Current		
Accumulated employee entitlements	**208,607**	205,109
	208,607	205,109
Non-current		
Accumulated employee entitlements	**130,278**	129,292
Site restoration – SM71 wells, pipelines & platform, SM58 E-1 & SM69 E-2 wells, SM69 pipelines & platform, SM58 wells, pipelines & platform	**9,964,086**	9,086,564
	10,094,364	9,215,856
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**9,086,564**	5,460,433
Additions to site restoration	**473,301**	3,384,936
Unwinding of discount on site restoration	**404,221**	241,195
Carrying amount at the end of the financial year	**9,964,086**	9,086,564

Provisions are recognised for the Group's restoration obligations for the SM71 wells, pipelines and platform, SM58 wells, pipelines and platform, SM58 E-1 well, SM69 E-2 well, SM69 pipelines & platform. The estimation of future costs associated with the abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until quite a few years into the future. Such cost estimates could be subject to revisions in subsequent years due to regulatory requirements, technological advances and other factors that are difficult to predict. Likewise, the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The additions for the year are due to increases in the future estimated costs of plugging and abandoning the current producing wells. The interest rates used to determine the restoration obligations at 30 June 2026 were approximately 4.55% (2025 approximately 4.45%) 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 (g).

15. Borrowings

	Consolidated	
	2026 US$	**2025 US$**
Current unsecured		
Insurance premium financing (interest bearing)*	**2,257,999**	2,381,127
Loans from directors and shareholder**	**3,088,865**	–
Current secured		
Prepaid oil revenue	**–**	2,111,111
Total current borrowings	**5,346,864**	4,492,238
Non-current unsecured		
Loans from directors and shareholder**	**–**	3,666,903
Total non-current borrowings	**–**	3,666,903

* The insurance premium financing bears an average 6.16% fixed interest rate, refer Note 29(c).

** During the 30 June 2025 financial year, the loan agreements were amended as follows: (a) interest of 12% is capitalised from 1 December 2024 (including 2% interest accrued from 1 August 2023 to 30 November 2024 was capitalised), and (b) the repayment date of 31 December 2025 was extended so that principal and capitalised interest will be repaid in 12 equal monthly instalments. Repayments of principal and interest commenced in April 2026 with final repayments due in March 2027.

16. Issued Capital

(a) Issued and Paid Up Capital	**138,916,729**	138,916,729

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

	30 June 2026		30 June 2025	
	Number	**US$**	**Number**	**US$**
Fully paid ordinary shares				
Balance at beginning of the financial year	**102,843,925**	**138,916,729**	1,081,395,102	138,916,729
Loan funded shares bought back	**–**	**–**	(50,340,000)	–
Share consolidation on a 1 for 10 basis	**–**	**–**	(928,211,177)	–
Closing balance at end of financial year	**102,843,925**	**138,916,729**	102,843,925	138,916,729
Less shares classified as treasury shares				
Balance at beginning of the financial year	**–**	**–**	40,840,000	–
Treasury shares cancelled after selective buyback	**–**	**–**	(40,840,000)	–
Closing balance at end of financial year	**–**	**–**	–	–
Closing balance at end of financial year	**102,843,925**	**138,916,729**	102,843,925	138,916,729

16. Issued Capital continued

(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.

At 30 June 2026, the Company had 102,843,925 ordinary shares on issue.

(d) Share Options

During the financial year, no share options were issued and none were on issue or converted.

17. Reserves

	Consolidated	
	2026 US$	**2025 US$**
Foreign currency translation reserve		
Balance at beginning of financial year	**(35,038)**	(37,365)
Currency translation movements for the year	**(119,191)**	2,327
Balance at end of financial year	**(154,229)**	(35,038)

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

Share option reserve		
Balance at beginning of financial year	**8,037,559**	8,037,559
Movements for the year	**–**	–
Balance at end of financial year	**8,037,559**	8,037,559

18. Auditors' Remuneration

Amounts received or due and receivable by Deloitte Touche Tohmatsu:		
Audit or review of the financial statements of the Group	**92,894**	87,869
	92,894	87,869

The auditors did not receive any other benefits (2025: nil).

19. Franking Credits

There are no franking credits available for distribution (2025: nil).

20. Commitments

(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 11. The inclusion of long term office rentals payments are not accounted for under AASB 16 for the year ended 30 June 2026.

	Consolidated	
	2026 US$	**2025 US$**
(a) Commitments for Office Lease Rental Payments		
Not longer than 1 year	**43,988**	38,837
Longer than 1 year, less than 5 years	**5,518**	5,548
	49,506	44,385

(b) Exploration Lease Expenditure Commitments

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

21. Controlled Entities

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

Name	Country of Domicile	Class of Share	Percentage Beneficially Owned
Byron Energy (Australia) Pty Ltd	Australia	Ordinary	100%
Byron Energy Inc	USA	Ordinary	100%
Byron Energy LLC	USA	Ordinary	100%

22. Cash Flow Reconciliation

	Consolidated	
	2026 US$	**2025 US$**
(a) Reconciliation of Loss from Ordinary Activities After Tax to Net Cashflows from Operations		
Loss for the year	**(25,885,618)**	(46,788,241)
Non cash flows in operating result:		
Amortisation oil and gas properties	**8,634,227**	11,911,786
Depreciation of property, plant, equipment	**2,679**	4,410
Depreciation of right of use assets	**212,652**	396,161
Impairment expense	**30,193,351**	46,332,034
Capitalised interest on related party loans	**–**	313,746
Finance cost of leased assets	**23,364**	53,018
Unwinding of discount on rehabilitation of oil and gas properties	**404,221**	241,195
Foreign exchange differences arising on translation of the parent entity group	**193,578**	(41,385)
Movements in working capital	**13,778,454**	**12,422,724**
(Increase)/decrease in assets:		
Trade and other receivables	**(278,658)**	1,861,187
Other assets	**177,214**	(21,023)
Increase/(decrease) in liabilities:		
Trade and other payables	**(1,657,930)**	985,109
Provisions	**(11,802)**	4,206
Net cash from operating activities	**12,007,278**	**15,252,203**
(b) Reconciliation of Cash		
Cash and cash equivalents comprise:		
Cash and bank balances	**4,211,854**	1,599,837

(c) Financing Facility

The Group had finance facilities at balance date consisting of loans from directors and shareholders that are fully drawn, prepaid revenue liability 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.

23. Contingent Liabilities

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

(a) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC (released post 30 June 2026).

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

(c) Supplemental Bonding Requirements by the BOEM

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

(d) Surety Bond Issuers' Collateral Requirements

The issuers of surety bonds in some cases have requested and received additional collateral related to surety bonds for exploration and development drilling and plugging and abandonment activities. Byron may be required to post collateral at any time pursuant to the terms of its agreement with sureties under its existing bonds, if they so demand at their discretion. As at 30 June 2026, Byron had collateral bond holdings of US$7,118,356 (2025: US$7,118,356), of which US$3,054,542 (2025: US$3,054,542) was cash collateralised.

(e) Other Claims

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

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

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

(f) Decommissioning Obligations

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

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

24. Related Party Transactions

The following related party transactions were made during the financial year ended 30 June 2026:

In March 2019, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with four of the Company's directors for loans from companies controlled by directors or loans from directors, for a total drawdown of US$2,000,000 and A$1,750,000. During the financial year ended 30 June 2024, the loan repayment date was extended to 31 December 2025 and an additional 2% interest started accruing on the loans from 1 August 2023, but not payable to the lenders until the revised repayment date. During the 30 June 2025 financial year, the loan agreements were further amended as follows: (a) interest of 12% is capitalised from 1 December 2024 (including 2% interest accrued from 1 August 2023 to 30 November 2024 now capitalised), and (b) the repayment date of 31 December 2025 was extended so that principal and capitalised interest will repaid in 12 equal monthly instalments and repayments. Repayments of principal and interest commenced in April 2026 with final repayments due in March 2027.

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, originally provided an unsecured loan of A$1,400,000 to the Company and total capitalised interest prior to the commencement of loan and interest repayments was A$283,141. The principal balance as at 30 June 2026 is A$1,050,000, and capitalised interest payable is A$212,355. Interest accrued and paid within the repayment period was A$46,160;
- Clapsy Pty Ltd and Poal Pty Ltd both companies controlled by Mr Paul Young, a director of the Company, originally provided unsecured loans of A$350,000 to the Company and total capitalised interest prior to the commencement of loan and interest repayments was A$70,785. The principal balance as at 30 June 2026 is A$262,500, and capitalised interest payable is A$53,089. Interest accrued and paid within the repayment period was A$11,540;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, a director of the Company, originally provided an unsecured loan of US$1,000,000 to the Company and capitalised interest prior to the commencement of loan and interest repayments was US$202,243. The principal balance as at 30 June 2026 is US$750,000, and capitalised interest payable is US$151,683. Interest accrued and paid within the repayment period was US$32,971; and
- Mr Charles Sands, a director of the Company, originally provided an unsecured loan of US$1,000,000 to the Company and capitalised interest prior to the commencement of loan and interest repayments was US$202,243 pre Australian Withholding Taxes ("pre AWT"). The principal balance as at 30 June 2026 is US$750,000, and capitalised interest payable is US$151,683 pre AWT. Interest accrued and paid within the repayment period was US$32,971 pre AWT.

25. Share-based Payments

No share options were issued, nor were any exercised and converted to fully paid shares during the 2026 financial year (2025: nil). There are no Employee Share Option plans in place.

Director and Key Management Personnel Equity Share Options

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

26. Key Management Personnel Compensation

Total aggregate remuneration of directors and key management personnel.

	Short Term Employee Benefits				Post Employment Benefits	
	Salaries and Fees US$	Short Term Cash Incentive US$	Other Benefits US$	Service Agreements US$	Superannuation US$	Total US$
Year 2026	**1,464,440**	**–**	**62,643**	**652,620**	**42,273**	**2,221,976**
Year 2025	1,446,890	–	59,282	623,476	38,702	2,168,350

27. Subsequent Events

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

- on 1 September 2026, Byron published its annual 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.

28. Interests in Joint Operations

As at 30 June 2026, Byron Energy Inc, a wholly owned subsidiary of the Company was a party, to the following joint operations:

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

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

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

29. 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	**2026 US$**	**2025 US$**
Financial assets		
Cash and cash equivalents	**4,211,854**	1,599,837
Trade and other receivables	**3,178,362**	2,903,137
Bonds and security deposits	**3,060,634**	3,060,254
	10,450,850	7,563,228
Financial liabilities		
Trade and other payables	**2,167,722**	8,456,995
Prepaid oil revenue	**–**	2,111,111
Insurance premium financing	**2,257,999**	2,381,127
Loans from related parties	**3,088,865**	3,666,903
	7,514,586	16,616,136

29. Financial Instruments continued

(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 2026 financial year, no dividends were paid (2025: 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.

(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$
2026					
Non-interest bearing	**–**	**3,155,698**	**22,664**	**–**	**–**
Non-interest rate bearing bonds	**–**	**–**	**–**		**6,092**
Interest rate bearing bonds	**0.70**		**–**	**–**	**3,054,542**
Variable interest rate instruments	**0.81**	**4,211,854**	**–**	**–**	**–**
2025					
Non-interest bearing	–	2,881,917	21,220	–	–
Non-interest rate bearing bonds	–	–	–		5,712
Interest rate bearing bonds	1.21		–	–	3,054,542
Variable interest rate instruments	1.83	1,599,837	–	–	–

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$
2026					
Non-interest bearing	**–**	**1,827,554**	**–**	**15,168**	**325,000**
Fixed interest rate instruments	**6.16**	**264,313**	**533,474**	**1,460,212**	**–**
Related party liabilities	**12.0**	**343,207**	**885,103**	**1,860,555**	**–**
2025					
Non-interest bearing	–	2,303,900	948,527	2,927,740	2,276,828
Fixed interest rate instruments	7.01	278,992	563,788	1,538,347	–
Prepaid oil revenue	12.88	1,055,556	1,055,555	–	–
Related party liabilities	12.0	–	–	–	3,666,903

(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, if any, 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 2026, 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$14,529 (2025: US$10,499) for an increase of 50 basis points, conversely a decrease of 50 basis points would result in a decrease of US$14,529 (2025: US$10,499) to the net profit. This is mainly due to the Group's exposure to variable interest rates on cash and cash equivalents.

29. Financial Instruments continued

(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	**2026 $**	**2025 $**	**2026 $**	**2025 $**
USA currency denominated	**10,266,061**	7,486,523	**6,063,968**	14,952,708
Australian currency denominated	**269,016**	117,107	**2,111,833**	2,539,585

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	**2026 US$**	**2025 US$**
Profit or equity	**218,679**	141,913

(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 may utilise commodity price hedge instruments at the Board's discretion to manages exposure to short term price fluctuations. These instruments may include forward sales, swaps, costless collars and/or puts under a master crude oil sales agreement with the Company's longstanding buyer of its crude oil production.

Byron's open hedge positions as of 30 June 2026 are contained on page 23 of this financial report.

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$1,547,373 (2025: US$1,176,994) 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$1,547,373 (2025: US$1,176,994) to the net profit.

30. Parent Entity Information

Financial Position	2026 US$	2025 US$
Assets		
Current assets	**39,202**	57,758
Non-current assets	**68,589,919**	95,171,464
Total assets	**68,629,121**	**95,229,222**
Liabilities		
Current liabilities	**3,188,358**	106,535
Non-current liabilities	**–**	3,677,115
Total liabilities	**3,188,358**	**3,783,650**
Net assets	**65,440,763**	**91,445,572**
Equity		
Issued capital	**138,252,986**	138,252,986
Accumulated losses	**(71,401,013)**	(41,882,657)
Foreign currency translation reserve	**(7,570,487)**	(11,084,034)
Share option reserve	**6,159,277**	6,159,277
Total Equity	**65,440,763**	**91,445,572**
Financial performance		
Loss for the year	**(29,518,356)**	(25,743,421)
Other comprehensive income/(loss)	**3,513,547**	(827,447)
Total comprehensive loss for the financial year	**(26,004,809)**	**(26,570,868)**

Expenditure Commitments

The parent entity has no expenditure commitments at the end of the 2026 financial year (2025: nil).

Guarantees

There were no guarantees entered into during the year by the parent entity in relation to the debts of its subsidiaries. As of 30 June 2026 the following guarantees were in place (i) 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 (ii) 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 and (iii) 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 (released post 30 June 2026).

Contingent Liabilities

The parent entity had no contingent liabilities at 30 June 2026 (2025: nil), other than those listed in Note 23 Contingent liabilities.

Consolidated Entity Disclosure Statement

Basis of Preparation

The Consolidated Entity disclosure statement has been prepared in accordance with s295 (3A)(a) of the *Corporations Act 2001* and includes the required information for Byron Energy Limited and the entities it controls in accordance with AASB 10 Consolidated Financial Statements.

Tax Residency

S295(3A)(vi) of the *Corporations Act 2001* defines tax residency as having the meaning in the *Income Tax Assessment Act 1997*. The determination of tax residency may involve judgement as there are different interpretations that could be adopted and which could give rise to different conclusions regarding residency. In determining tax residence, the Group has applied the following interpretations:

Australian Tax Residency

Current legislation and judicial precent has been applied, including having regard to the Tax Commissioner's public guidance.

Foreign Tax Residency

Where appropriate, independent tax advisors have been engaged to assist in the determination of tax residence to ensure applicable foreign tax legislation has been complied with.

Name of Entity	Type of Entity	Trustee, Partner or Participant in Joint Venture	% of Share Capital Held	Country of Incorporation	Australian Resident or Foreign Resident (For Tax Purposes)	Foreign Tax Jurisdiction
Byron Energy Limited	Body corporate	n/a	n/a	Australia	Australian	Australia
Byron Energy (Australia) Pty Ltd	Body corporate	n/a	100%	Australia	Australian	Australia
Byron Energy LLC	Body corporate	n/a	100%	USA	Foreign	USA
Byron Energy INC	Body corporate	n/a	100%	USA	Foreign	USA

Directors' Declaration

The directors declare that, in the directors' opinion:

a. the attached consolidated financial statements and notes are in accordance with the *Corporations Act 2001*, including:
   i. giving a true and fair view of the consolidated entity's financial position as at 30 June 2026 and its performance for the year ended on that date; and
   ii. complying with the Australian Accounting Standards and the *Corporations Regulations 2001*;
b. there are reasonable grounds to believe that the company will be able to pay its debts as and when they become due and payable;
c. the attached financial statements are in compliance with IFRS Accounting Standards, as stated in Note 1 to the consolidated financial statements; and
d. the attached consolidated entity disclosure statement is true and correct.

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

On behalf of the directors

D. G. Battersby
Chairman

29 September 2026

Independent Auditor's Report

To the members of Byron Energy Limited

Deloitte.

Deloitte Touche Tohmatsu
ABN 74 490 121 060

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

Opinion

We have audited the financial report of Byron Energy Limited (the "Company") and its subsidiaries (the "Group") which comprises the consolidated statement of financial position as at 30 June 2026, 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 material accounting policy information and other explanatory information, the consolidated entity disclosure statement and the directors' declaration.

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

- Giving a true and fair view of the Group's financial position as at 30 June 2026 and of its financial performance for the year then ended; and
- Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* issued by the Accounting Professional & Ethical Standards Board Limited (the Code) that are relevant to audits 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 Entity, would be in 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.

Other information

The directors are responsible for the other information. The other information comprises the information included in the Group's annual report for the year ended 30 June 2026 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.

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Responsibilities of the directors for the financial report

The directors of the Entity are responsible:

- For the preparation of the financial report in accordance with the *Corporations Act 2001*, including giving a true and fair view of the financial position and performance of the Group in accordance with Australian Accounting Standards; and
- For such internal control as the directors determine is necessary to enable the preparation of the financial report in accordance with the *Corporations Act 2001*, including giving a true and fair view of the financial position and performance of the Group, and is free from material misstatement, whether due to fraud or error.

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

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

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

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.
- Conclude on the appropriateness of the directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group as a basis for forming an opinion on the Group financial report. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

Deloitte.

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.

DELOITTE TOUCHE TOHMATSU

DELOITTE TOUCHE TOHMATSU

Jane Fisher
Partner
Chartered Accountants
Melbourne, 29 September 2026

Corporate Directory

Directors

Doug Battersby (Non-Executive & Chairman)

Maynard Smith (Executive Director & CEO)

Prent Kallenberger (Executive Director)

William Sack (Executive Director)

Charles Sands (Non-Executive)

Paul Young (Non-Executive)

Chief Executive Officer

Maynard Smith

Chief Financial Officer and Company Secretary

Nick Filipovic

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Legal Adviser

Piper Alderman
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Auditors

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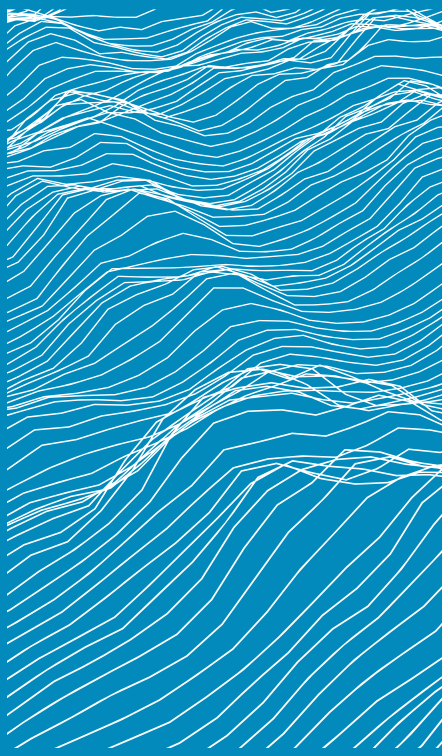
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